D.2 Pipeline Safety and Risk of Accidents

In this section, the risks to public safety and the environment that could result from the construction activities, pipeline operation (unintentional releases) and project abandonment are presented. It should be noted that the text of this section was based on only conceptual engineering drawings and other data; detailed engineering drawings, calculations, specifications and other supporting data will not be available for review until after the Final Environmental Impact Report has been prepared.

D.2.1 Pipeline Incident Data

SFPP is proposing to construct and operate a new 20-inch petroleum pipeline from the existing SFPP Concord Station in Contra Costa County to the existing SFPP Sacramento Station in the City of West Sacramento, California. The proposed pipeline would be approximately 70 miles long and would transport refined petroleum products. The pipeline would be designed to operate at the limits of an ANSI Class 600 system, 1,440 pounds per square inch gauge (psig).

The purpose of the new pipeline is to meet projected market demand by replacing SFPP's existing 36-year old (completed in 1967), 61.4-mile, 14-inch-diameter pipeline between Concord and West Sacramento with a new 20-inch-diameter line, with additional capacity. The existing pipeline is located primarily within Union Pacific Railroad (UPRR) right-of-way (ROW). Upon completion of the Proposed Project, most of the existing pipeline would be decommissioned. However, 6,000 feet of the existing 14-inch line would continue to be used for the crossing of the Carquinez Strait.

The pipeline profile is generally flat, with over 60 water crossings of various sizes — from drainage channels to the Carquinez Strait. The majority of the proposed 70-mile route lies in rural areas. Roughly 15 miles of the line is located in urban and suburban areas of the Cities of Fairfield, Suisun, and West Sacramento. A large percentage of the rural route is located in saturated soils, susceptible to liquefaction. The proposed route crosses three active and one potentially active earthquake faults.

This section develops pipeline incident data for SFPP's existing 14-inch pipeline, for the proposed new 20-inch pipeline, and for the Existing Pipeline ROW Alternative. Incident data for these pipelines is compared with general incident figures for the No Project Alternative.

D.2.1.1 Methodology

In this section, the anticipated frequency of unintentional releases (incident rate) will be determined for releases from the existing and proposed SFPP pipeline system. The incident rate presented is intended to be the average incident rate, to be expected over a 50-year project life. Because the frequency of accidents increases as pipelines age, the actual incident rate will likely be somewhat less than the value presented during the early period of operation. During the latter years of operation, the rate will likely be somewhat higher (the difference between a new pipeline compared to a pipeline in operation for close to 50 years, or more in the case of the existing pipe). It should also be noted that new technologies may become available that may reduce the risk in future years.

The anticipated frequency of unintentional releases is based primarily on the 1981 through 1990 data collected for California's regulated interstate and intrastate hazardous liquid pipelines (*California Hazardous Liquid Pipeline Risk Assessment*, prepared for the California State Fire Marshal, 1994). The report included a complete inventory of all 7,800 miles of interstate and intrastate hazardous liquid pipelines within the State. It also included an audit of all 514 unintentional releases that occurred within this 10-year period. Based on a review of the national and international data available,[1] using this California data is considered appropriate, for the following reasons:

1. The California data is the only completely audited, recent, relatively large data sample available. A team of field technicians visited the operational sites of every regulated pipeline operator within the State. The team spent between one and five days at each site reviewing insurance records, release records, pipeline inventory data, drawings, internal incident reports, etc. and interviewing operator personnel. Using this approach allowed the team to collect data for very small releases, which were not reportable during the 1980s.

2. The pipelines included in the California study are representative of the SFPP pipeline system (e.g., similar diameter, all hazardous liquid lines, variable terrain, all steel, etc.). Specifically, this study included 7,800 miles of interstate and intrastate regulated hazardous liquid pipelines. The length weighted mean pipe diameter of these lines was 12.3 inches. Approximately 43% of the pipeline mileage carried crude oil, 50% carried refined petroleum products, and 7% carried other hazardous liquids. (This study did not include crude oil flow lines, gathering lines, etc.)

3. The study included a statistical analysis of the pipe contents (crude oil, refined petroleum projects, highly volatile liquids, or other) effects on the likelihood of an unintentional release. Specifically, crude oil lines were found to raise the possibility of an unintentional release caused by external corrosion. However, the study found that this was primarily a result of higher operating temperatures and pipe age, not the direct result of the pipe contents. These results have been incorporated into the analyses performed in this document.

4. The California data included a complete pipeline inventory and unintentional release data with many parameters. As a result, it allowed the authors to investigate the effects of various operational and design considerations (e.g., operating temperature, period of construction, etc.). The conclusions drawn from the California study are useful in assessing the risks associated with the existing and proposed SFPP pipeline system. The California study identified the effects of several pipeline parameters on the overall incident rates. Using these data facilitate the development of the anticipated frequency of unintentional releases from the existing and proposed SFPP using actual pipeline construction and operational conditions.

5. The reader should note that the frequency of unintentional releases presented in the California study are higher than those reported by other sources. The higher frequency is due to the inclusion of all releases, regardless of release volume. Other sources only include releases meeting certain criteria; they typically only include DOT reportable releases.

6. Since the California study included a complete pipeline inventory, including the actual length of pipe installed for each of several parameters (e.g., operating temperature, external coating, type of steel, operating pipe stresses as a function of the specified minimum pipe stress, etc.), the data enabled a very comprehensive statistical analysis. Multinomial logic regressions were performed to evaluate the probability of pipeline incidents considering each of these variables. Using these statistical results and other data, anticipated pipeline incident rates have been developed for this project.

7. The California study also included complete release volume distribution data. These data included releases smaller than those included in other sources. These data have been used to develop the predicted frequency of releases of various volumes.

8. Although the California data set is now over 10 years old, national and international data suggest that the frequency of unintentional releases and their causes have not changed appreciably since the study was conducted. Although there are slight annual variations, the frequencies of releases, injuries, and fatalities have remained essentially constant since 1990.

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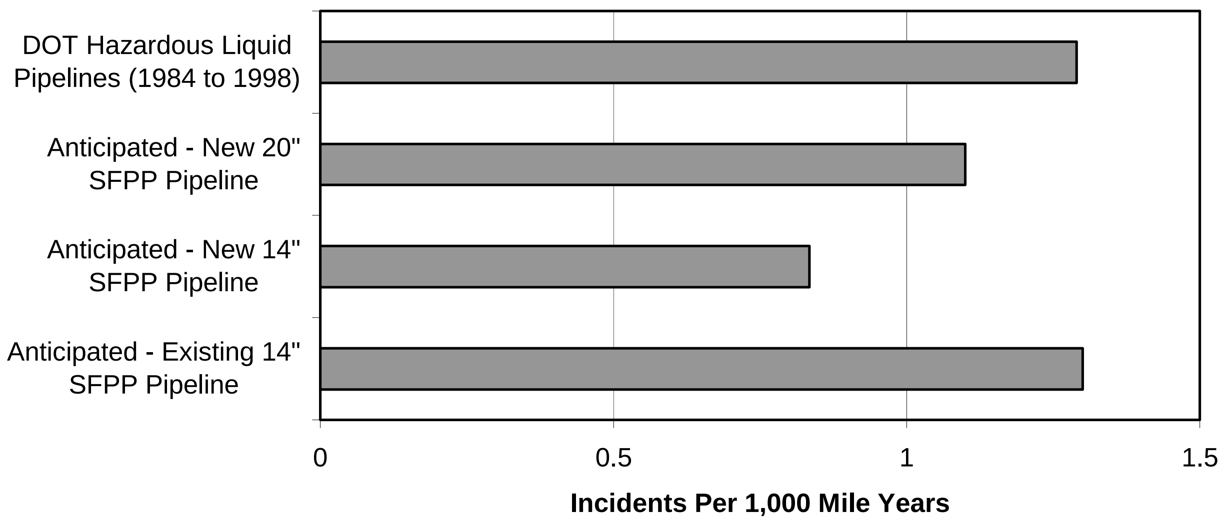
[1] *National Transportation Statistics* (U.S. Department of Transportation, various years); *Annual Report on Pipeline Safety* (U.S. Department of Transportation, 1986 through present); *Performance of Oil Industry Cross Country Pipelines in Western Europe, Statistical Summary of Reported Spillages* (CONCAWE, various annual reports).

In order to evaluate this approach, the frequency of anticipated unintentional releases of 50 barrels or greater (DOT reporting criteria from 1984 through 2002) has been analyzed. There is a good correlation between the anticipated frequency of releases from the existing and proposed SFPP pipelines to the national data. The anticipated frequency of releases from the proposed new pipe is lower than the DOT data. And, the anticipated frequency of releases from the existing SFPP pipeline is essentially the same as that found in the national data. Therefore, the general approach is considered to be reasonable. A comparison of these data is presented graphically in Figure D.2-1.

Figure D.2-1.
Incident Rate Comparison – Releases 50 Barrels or Larger



Notes:
1. The DOT data represented above, includes releases which occurred within the regulated portions of pump stations and terminals, as well as those which occurred on regulated pipelines. These data also include some releases that are smaller than 50 barrels, which meet specified criteria.
2. The anticipated rates for the existing and proposed pipelines include pipeline releases only.
3. The "New 14 SFPP Pipeline" incident rate applies to the short segments of new 14" pipe that would be used to connect the existing 14" pipe beneath the Carquinez Straight to the proposed 20" line.

D.2.1.2 Anticipated Frequency of Unintentional Releases from Existing Pipeline

The California study analyzed the effects of each potential incident cause. This study concluded that pipelines constructed before 1950, especially those constructed before 1940, and pipelines operated at elevated temperatures had significantly higher unintentional release rates, primarily affected by increased external corrosion. The majority of the existing SFPP pipeline system was constructed in 1967. The pipeline is operated at ambient temperatures. As a result, the release incident rate for this pipeline section will be affected as described in the following paragraphs.

The units normally used for expressing the frequency of unintentional releases are *incidents per 1,000 mile-years.* This unit provides a means of predicting the number of incidents expected for a given length of line, over a given period of time. For example, if one considered an incident rate of 1.0 incident per 1,000 mile-years, one would expect one incident per year on a 1,000-mile pipeline. Alternatively, one would expect one incident every 1,000 years on a one-mile pipeline. Using this unit, the frequencies of occurrence can be calculated for any combination of pipeline length and time interval.

Effects of Pipeline Age on External Corrosion

The California study found that the frequency of unintentional releases (of all volumes) caused by external corrosion was 4.18 incidents per 1,000 mile-years. However, pipelines constructed in the 1950s had an external corrosion incident rate of 2.47 incidents per 1,000 mile-years; those constructed in the 1960s, 1970s and 1980s had external corrosion incident rates of 1.47, 1.24, and 0.00 incidents per 1,000 mile-years respectively. On the other hand, pipelines constructed before 1940 and those constructed during the 1940s, had external corrosion incident rates of 14.12 and 4.24 incidents per 1,000 years respectively. The statistical analyses performed in the California study indicated that the decade of pipeline construction directly affected the incident rate. (The reader should note that this figure included all releases, regardless of release volume. The majority of these releases would not require DOT reporting. As a result, the reader should not attempt to directly compare these values to those presented from other sources. They can only be compared after the release volume distribution has been considered.)

During the 1940s and 1950s, significant improvements were made in pipeline construction techniques. Relative to external corrosion, the primary improvements included advances in external coatings and more widespread use of these coatings and cathodic protection systems. These items account for the significant reduction in external corrosion incident rates over pipelines constructed prior to the 1940s. For newer pipelines, it is impossible to isolate the individual affects of pipe age and other improvements (e.g., technology, construction techniques, the more widespread use of high quality external coatings and cathodic protection systems).

Table D.2-1 below presents the California data by decade of pipeline construction. In reviewing these data, it is important to note that the California study was completed in 1993. At that time, the pipe constructed during the 1980s had only been in operation for a few years. One should not conclude that because there were no releases caused by external corrosion for pipelines constructed after 1980 that corrosion is not a concern in newer pipelines. Rather, these data reflect the fact that the relatively new pipe had not yet been in service long enough for external corrosion to extend through the pipe wall, resulting in an unintentional release. As each decade passes, the pipe constructed during the 1980s will likely have an external corrosion–caused unintentional release rate similar to that shown in the table for the prior decade. For example, during the 2000s, the frequency of releases caused by external corrosion for pipe constructed in the 1980s is expected be around one incident per 1,000 mile-years (similar to the 1970s data in Table D.2-1). The frequency will likely stabilize around one to two incidents per 1,000 mile-years, approximately the 1960s rate, after significant improvements were made in pipe and coating technology. As noted earlier, significant improvements were made in the 1940s and 1950s. Improvement since this time has been steady, but it has been much more gradual.

Effects of Operating Temperature on External Corrosion

The statistical analyses performed in the California study indicated that operating temperature directly affected the frequency of unintentional releases. Considering all pipelines, regardless of decade of construction, those that were operated near ambient temperatures had an external corrosion–caused incident rate of 1.33 incidents per 1,000 mile-years. The incident rate rose dramatically as the operating temperature was increased.

Table D.2-1. Unintentional Release Rates by Decade of Construction *

Incident Cause	Pre-1940	1940-49	1950-59	1960-69	1970-79	1980-89
External corrosion	14.12	4.24	2.47	1.47	1.24	0.00
Internal corrosion	0.38	0.27	0.10	0.16	0.00	0.28
3rd party - construction	1.96	1.06	0.68	0.66	0.25	0.28
3rd party - farm equipment	0.53	0.33	0.05	0.00	0.00	0.00
3rd party - train derailment	0.00	0.00	0.00	0.05	0.25	0.00
3rd party - external corrosion	0.45	0.00	0.10	0.33	0.00	0.00
3rd party - other	0.30	0.13	0.05	0.05	0.00	0.00
Human operating error	0.30	0.13	0.00	0.11	0.25	0.00
Design flaw	0.08	0.00	0.00	0.00	0.00	0.14
Equipment malfunction	0.38	0.53	0.10	0.60	1.24	0.00
Maintenance	0.00	0.00	0.24	0.00	0.00	0.00
Weld failure	0.38	0.27	0.15	0.44	0.25	0.00
Other	0.83	0.13	0.24	0.27	0.25	0.28
Total	19.70	8.08	4.17	4.15	3.72	0.97

Source: Payne, 1993
* Units – Unintentional Release Rate = number of incidents per 1,000 mile-years

Table D.2-2 indicates that the external corrosion incident rates for the California lines operated at various temperatures ranged from 0.48 to 11.36 incidents per 1,000 mile-years. However, the lines operated between 130 and 159°F had a 1947 mean year of pipeline construction; as discussed earlier, pipe age also significantly affected the incident rate. This effect is also reflected in these data. The existing and proposed SFPP pipeline system has been, and will continue to be operated at ambient temperatures (70–99°F). However, it has been designed for a maximum operating temperature of 110°F.

Table D.2-2. Unintentional Release Rates by Design Operating Temperature

Incident Cause	0-69°F	70-99°F	100-129°F	130-159°F	160°F+
External corrosion	0.48	1.33	7.11	11.36	11.31
Internal corrosion	0.00	0.21	0.32	0.57	0.08
3rd party - construction	1.91	0.94	0.95	0.57	0.60
3rd party - farm equipment	0.00	0.30	0.47	0.00	0.08
3rd party - train derailment	0.00	0.04	0.00	0.00	0.00
3rd party - external corrosion	0.00	0.06	0.16	0.00	0.15
3rd party - other	0.00	0.24	0.16	0.00	0.15
Human operating error	0.00	0.11	0.00	0.00	0.23
Design flaw	0.00	0.04	0.00	0.00	0.00
Equipment malfunction	0.00	0.24	0.16	0.57	0.98
Maintenance	0.00	0.09	0.16	0.00	0.00
Weld failure	0.00	0.19	0.32	0.00	0.60
Other	0.00	0.21	0.11	1.14	0.45
Total	2.38	4.01	10.90	14.20	14.63

Source: Payne, 1993
Units – Unintentional Release Rate, incidents per 1,000 mile-years

Overall Effects of External Corrosion

Using the data presented in Tables D.2-1 and D.2-2, the anticipated external corrosion–caused unintentional release rate has been developed for the existing SFPP pipeline system. This system will normally be operated at ambient temperatures, using externally coated pipe, with an impressed current cathodic protection system; the anticipated frequency of external corrosion–caused unintentional releases will likely be approximately 2 incidents per 1,000 mile-years. This rate is slightly higher than both the data for pipelines constructed during the 1960s and the data for pipelines operated between 70 and 99°F. The proposed frequency is intended to reflect the average value over a 50-year project life.

Other Causes of Unintentional Releases

Third Party Damage. The California study found that the overall frequency of third party damage–caused unintentional releases was 1.46 incidents per 1,000 mile-years. For pipelines constructed in the 1950s, the frequency was only 0.88 incidents per 1,000 mile-years; it was even lower for newer lines. These lower values resulted primarily from the increased awareness of the threat from third party damage to pipeline facilities; newer lines have benefited from improved line marking, one-call dig alert systems, avoidance of high risk areas, improved documentation, increased depth of cover, and public awareness programs.

The frequency of unintentional releases caused by third party damage for all volume releases from the existing line is estimated to be approximately one incident per 1,000 mile-years.

Internal Corrosion. Although the possibility of an internal corrosion/erosion–caused unintentional release is low, the possibility does exist. A frequency of 0.19 incidents per 1,000 mile-years for unintentional releases caused by internal corrosion is consistent with historical data. This is the rate found in the California study. Although the actual internal corrosion–caused incident rate was found to be lower for refined petroleum product lines, the statistical analysis indicated that the pipe contents were not a factor. Operating temperature however was a factor. The proposed incident rate corresponds to an operating temperature of 97.9°F, which is close to the pipeline design temperature.

Human Operating Error. A frequency of unintentional releases caused by human operating error of 0.11 incidents per 1,000 mile-years has been used, based on the data obtained from the California study.

Design Flaw (Engineering). Based on the California data, the frequency of unintentional releases caused by design flaw/error is 0.03 incidents per 1,000 mile-years. Although these incidents are rare, they do occur. Often, an unintentional release that is caused by a design flaw is categorized improperly. The designation of a release cause is often subjective. For example, should a pipeline be severed during a landslide, the operator may indicate that the cause was third party damage. However, it may have been a design error or oversight that placed the pipeline in the hazardous location in the first place. Design errors cannot be eliminated. The proposed frequency of unintentional releases from this cause is reasonable, and is consistent with historical data.

Equipment Malfunction. A frequency of equipment malfunction–caused unintentional releases of 0.37 incidents per 1,000 mile-years has been used, consistent with the California study.

Maintenance. A frequency of improper maintenance–caused unintentional releases of 0.07 incidents per 1,000 mile-years has been used, based on the California study.

Other or Unknown Causes. Based on the California study, a frequency of unintentional releases caused by other or unknown sources of 0.45 incidents per 1,000 mile-years has been used.

Pre-1970 Electric Resistance Welded (ERW) Pipe. The pipeline industry has experienced some problems with pre-1970 ERW pipe. In 1988, the DOT issued an alert notice to pipeline operators which recommended that they consider hydrostatically testing these lines, avoid increasing long-standing operating pressures, evaluate cathodic protection system effectiveness, and conduct metallurgical examinations of any ERW weld seam failures. Subsequently, 49 CFR 195, Section 195.302 was promulgated to require all hazardous liquid pipelines containing more than 50% by mileage of ERW pipe manufactured before 1970, which had not already been tested, to be pressure tested by December 7, 1999.

The vast majority of the existing 14-inch SFPP pipeline was manufactured before 1970 using a longitudinal weld seam, which was welded using the ERW process. The line has also experienced releases caused by longitudinal weld seam defects.

Overall Anticipated Frequency of Unintentional Releases from the Existing SFPP 14-inch Pipeline

This section illustrates the existing baseline of risk along the pipeline corridor. Using the data described above, the frequency of unintentional releases for all releases, regardless of volume, is expected to be 4.48 incidents per 1,000 mile-years. For the existing 61.4-mile SFPP pipeline, this will result in an anticipated unintentional release every four years, with a DOT reportable leak (50 barrels or greater) occurring every 12.5 years.[2] As stated earlier, the actual incident rates are likely to be less at the present time, and higher as the existing pipeline continues to age. These incident rates do not consider major new detection and prevention technologies that might be developed during the next 50 years. The anticipated incident rate for DOT reportable releases (> 50 barrels) is 1.30 incidents per 1,000 mile-years. This data is summarized in Table D.2-3.

Table D.2-3. Anticipated Unintentional Releases from Existing 61.4-Mile, 14-Inch-Diameter SFPP Pipeline

Unintentional Release Cause	Incident Rate (per 1,000 mile-years)	Pipeline Section Length (miles)	Unintentional Releases per Year	Anticipated Unintentional Releases Over 50-Year Project Life
External corrosion	2.00	61.4	0.1228	6.1
Internal corrosion	0.19	61.4	0.0117	0.6
3rd party damage	1.00	61.4	0.0614	3.1
Human operating error	0.11	61.4	0.0068	0.3
Design flaw	0.03	61.4	0.0018	0.1
Equipment malfunction	0.37	61.4	0.0227	1.1
Maintenance	0.07	61.4	0.0043	0.2
Weld failure	0.26	61.4	0.0160	0.8
Other	0.45	61.4	0.0276	1.4
Total, all releases, regardless of unintentional release volume	**4.48**	**61.4**	**0.2751**	**13.7**
DOT reportable releases (50 barrels or greater) - 14-inch line	1.30	61.4	0.0798	4.0

It is often desirable to analyze the anticipated frequency of unintentional releases at a specific location along a pipeline. For example, what is the likelihood of an unintentional release occurring in one's neighborhood? In Table D.2-4, the anticipated frequencies of unintentional releases are provided for any one-mile segment of the existing 14-inch SFPP pipeline.

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[2] Table D.6-8 (Section D.6, Environmental Contamination and Hazardous Materials) in its discussion of the Existing Pipeline ROW Alternative, lists 11 spills that occurred on the existing 14-inch pipeline between 1989 and 2000. This summary was based on remediation reports provided by SFPP and is not considered to represent a complete record of accidents on the existing pipeline.

Table D.2-4. Anticipated Unintentional Releases from Any One-Mile Section of Existing 61.4-Mile, 14-Inch-Diameter SFPP Pipeline

Unintentional Release Cause	Incident Rate (per 1,000 mile-years)	Pipeline Section Length (miles)	Unintentional Releases per Year	Anticipated Unintentional Releases Over 50-Year Project Life
External corrosion	2.00	1	0.0020	0.10
Internal corrosion	0.19	1	0.0002	0.01
3rd party - construction	1.00	1	0.0010	0.05
Human operating error	0.11	1	0.0001	0.01
Design flaw	0.03	1	0.0000	0.00
Equipment malfunction	0.37	1	0.0004	0.02
Maintenance	0.07	1	0.0001	0.00
Weld failure	0.26	1	0.0003	0.01
Other	0.45	1	0.0005	0.02
Total, all releases, regardless of unintentional release volume	4.48	1	0.0045	0.22
DOT reportable releases (50 barrels or greater) - 14-inch line	1.30	1	0.0013	0.07

D.2.1.3 Anticipated Frequency of Unintentional Releases from Proposed Pipeline

In the following paragraphs, the anticipated frequency of unintentional releases is presented for the proposed new pipe construction. These data apply to both the Proposed Project and the Existing Pipeline ROW Alternative. These calculations will be based primarily on the 1981 through 1990 data collected for California's regulated interstate and intrastate hazardous liquid pipelines, as presented in the immediately preceding paragraphs.

Overall Effects of External Corrosion

Using the data presented in Tables D.2-1 and D.2-2, the anticipated frequency of external corrosion–caused unintentional releases from the proposed and alternative new SFPP pipeline segments has been developed. These segments will normally be operated at ambient temperatures, using modern external pipe coating, with an impressed current cathodic protection system; the anticipated frequency of external corrosion–caused unintentional releases will eventually be 1 release per 1,000 mile-years. During the first several years of pipeline operation, the frequency of these releases will likely approach zero. However, during the 50-year project life, the frequency of unintentional releases caused by external corrosion would be expected to increase, as the pipe and coating age.

Other Causes of Releases

Third Party Damage. The frequency of third party damage–caused unintentional releases from the new pipeline segments is anticipated to be less than 0.4 incidents per 1,000 mile-years. This is the average value presented in the California study for pipelines installed in the 1970s and 1980s.

Other Causes. The frequency of unintentional releases caused by internal corrosion, human operating error, design flaw, equipment malfunction, maintenance, and other causes is expected to be similar to the existing pipeline, when averaged over the 50-year project life.

Overall Anticipated Frequency of Unintentional Releases from New SFPP Pipeline

The frequency of unintentional releases from the proposed and alternative new pipeline segments is expected to be 2.88 incidents per 1,000 mile-years, as summarized in Tables D.2-5, D.2-6, and D.2-7. The anticipated frequency of unintentional releases for DOT reportable releases (> 50 barrels) from the 20-inch-diameter pipe is 1.10 incidents per 1,000 mile-years.

D.2.1.4 Baseline Data - Unintentional Release Volume Distribution

Occasionally, the unintentional release data presented in the prior paragraphs of this section are mistakenly assumed to represent the likelihood of a worst-case release. However, these figures represent the probable likelihood of any release, regardless of volume. In fact, most releases are relatively small. In the following paragraphs, the release volume distribution will be developed. The determination of worst-case release volumes is site-specific; worst-case release scenarios are presented in Section D.2.3.5 for four specific sites.

Regulated California Hazardous Liquid Pipeline Release Size Distribution, 1981–1990

During the 10-year study period analyzed in the California Hazardous Liquid Pipeline Study, the following release distribution data were identified and are worth noting:

- 27% of the incidents resulted in release volumes of one barrel (42 gallons) or less
- The median release volume was 5 barrels (210 gallons)
- 61% of the incidents resulted in release volumes of 10 barrels (420 gallons) or less
- 67% of the incidents resulted in release volumes of 25 barrels (1,050 gallons) or less
- 74% of the incidents resulted in release volumes of 50 barrels (2,100 gallons) or less
- 82% of the incidents resulted in release volumes of 100 barrels (4,200 gallons) or less
- 90% of the incidents resulted in release volumes of 650 barrels (27,300 gallons) or less.

The California study included a complete spill size distribution for all of the leaks that occurred during the 10-year study period. To make these data useful, the spill sizes were normalized to a common pipe diameter, using the pipe cross sectional area.

Table D.2-5. Anticipated Unintentional Releases from Proposed New 70-Mile, 20-Inch-Diameter SFPP Pipeline

Unintentional Release Cause	Incident Rate (per 1,000 mile-years)	Pipeline Section Length (miles)	Unintentional Releases per Year	Anticipated Unintentional Releases Over 50-Year Project Life
External corrosion	1.00	70	0.0700	3.5
Internal corrosion	0.19	70	0.0133	0.7
3rd party - construction	0.40	70	0.0280	1.4
Human operating error	0.11	70	0.0077	0.4
Design flaw	0.03	70	0.0021	0.1
Equipment malfunction	0.37	70	0.0259	1.3
Maintenance	0.07	70	0.0049	0.2
Weld failure	0.26	70	0.0182	0.9
Other	0.45	70	0.0315	1.6
Total, all unintentional releases, regardless of volume	2.88	70	0.2016	10.1
DOT reportable unintentional releases (50 barrels or greater) - 20-inch line	1.10	70	0.0770	3.9

Table D.2-6. Anticipated Unintentional Releases from Existing Pipeline ROW Alternative Route, New 61.4-Mile, 20-Inch-Diameter SFPP Pipeline

Unintentional Release Cause	Incident Rate (per 1,000 mile-years)	Pipeline Section Length (miles)	Unintentional Releases per Year	Anticipated Unintentional Releases Over 50-Year Project Life
External corrosion	1.00	61.4	0.0614	3.1
Internal corrosion	0.19	61.4	0.0117	0.6
3rd party - construction	0.40	61.4	0.0246	1.2
Human operating error	0.11	61.4	0.0068	0.3
Design flaw	0.03	61.4	0.0018	0.1
Equipment malfunction	0.37	61.4	0.0227	1.1
Maintenance	0.07	61.4	0.0043	0.2
Weld failure	0.26	61.4	0.0160	0.8
Other	0.45	61.4	0.0276	1.4
Total, all unintentional releases, regardless of volume	2.88	61.4	0.1768	8.8
DOT reportable unintentional releases (50 barrels or greater) - 20-inch line	1.10	61.4	0.0675	3.4

Table D.2-7. Anticipated Unintentional Releases from One-Mile Section of Proposed or Alternative New 20-Inch-Diameter and 14-Inch-Diameter SFPP Pipeline

Unintentional Release Cause	Incident Rate (per 1,000 mile-years)	Pipeline Section Length (miles)	Unintentional Releases per Year	Anticipated Unintentional Releases Over 50-Year Project Life
External corrosion	1.00	1	0.0010	0.05
Internal corrosion	0.19	1	0.0002	0.01
3rd party - construction	0.40	1	0.0004	0.02
Human operating error	0.11	1	0.0001	0.01
Design flaw	0.03	1	0.0000	0.00
Equipment malfunction	0.37	1	0.0004	0.02
Maintenance	0.07	1	0.0001	0.00
Weld failure	0.26	1	0.0003	0.01
Other	0.45	1	0.0005	0.02
Total, all unintentional releases, regardless of volume	2.88	1	0.0029	0.14
DOT reportable unintentional releases (50 barrels or greater) - 20-inch line	1.10	1	0.0011	0.06

By combining the anticipated frequency of unintentional release data presented in the preceding paragraphs with the anticipated release volume distribution, one can predict the anticipated recurrence interval of various sized releases from the existing and proposed pipelines. The resulting data are presented in Tables D.2-8, D.2-9, and D.2-10. Although the information on anticipated releases from the entire pipeline length (Columns A and B) is useful, one often needs data for much shorter line sections to evaluate the risk to locally sensitive areas or a particular receptor. For this purpose, the probable recurrence interval for various sized releases from a one-mile section of line are also presented (in Column C).

Table D.2-8. Anticipated Unintentional Release Volume Distribution from Existing 61.4-Mile, 14-Inch-Diameter SFPP Pipeline

	A	B	C
Unintentional Release Volume, Barrels (gallons)	Anticipated Incidents Per Year – Existing 61.4-Mile, 14-Inch-Diameter SFPP Pipeline	Anticipated Unintentional Releases Over 50-Year Project Life – Existing 61.4-Mile, 14-Inch-Diameter SFPP Pipeline	Anticipated Unintentional Releases Over 50-Year Project Life – Any 1-Mile Section of Existing 61.4-Mile, 14-Inch-Diameter SFPP Pipeline
>1 (42)	0.2554	12.77	0.208
>5 (210)	0.1670	8.35	0.136
>10 (420)	0.1326	6.63	0.108
>50 (2,100)	0.0798	3.98	0.065
>100 (4,200)	0.0620	3.11	0.050
>500 (21,000)	0.0360	1.80	0.029
>1,000 (42,000)	0.0262	1.31	0.021
>5,000 (210,000)	0.0064	0.32	0.005
>10,000 (420,000)	0.0039	0.19	0.003

Table D.2-9. Anticipated Unintentional Release Volume Distribution from Proposed New 70-Mile, 20-Inch-Diameter SFPP Pipeline

	A	B	C
Unintentional Release Volume, Barrels (gallons)	Anticipated Incidents Per Year – Proposed New 70-Mile, 20-Inch-Diameter SFPP Pipeline	Anticipated Unintentional Releases Over 50-Year Project Life – Proposed New 70-Mile, 20-Inch-Diameter SFPP Pipeline	Anticipated Unintentional Releases Over 50-Year Project Life – Any 1-Mile Section of Proposed New 70-Mile, 20-Inch-Diameter SFPP Pipeline
>1 (42)	0.1925	9.63	0.138
>5 (210)	0.1470	7.35	0.105
>10 (420)	0.1225	6.12	0.088
>50 (2,100)	0.0770	3.86	0.055
>100 (4,200)	0.0584	2.92	0.042
>500 (21,000)	0.0341	1.71	0.024
>1,000 (42,000)	0.0269	1.34	0.019
>5,000 (210,000)	0.0095	0.47	0.007
>10,000 (420,000)	0.0048	0.24	0.003

Tables D.2-11 and D.2-12 present comparative data on accidents and injuries/fatalities for the Proposed Project with the Existing Pipeline ROW Alternative and the No Project Alternative.

D.2.1.5 Block Valve Effectiveness

It is often assumed that when a release occurs, the complete volume between adjacent block valves will be released from the pipeline; but this is usually not the case. The *California Hazardous Liquid Pipeline Risk Assessment* (Payne, 1993) included an analysis of block valve effectiveness. As noted earlier, this study analyzed the release history and several engineering parameters for 7,800 miles of hazardous liquid pipelines over a ten-year period. The data collected led to the following block valve effectiveness findings:

Table D.2-10. Anticipated Unintentional Release Volume Distribution from Existing Pipeline ROW Alternative Route, New 61.4-Mile, 20-Inch-Diameter SFPP Pipeline

	A	B	C
Unintentional Release Volume, Barrels (gallons)	Anticipated Incidents Per Year – Alternative New 61.4-Mile, 20-Inch-Diameter SFPP Pipeline	Anticipated Unintentional Releases Over 50-Year Project Life – Alternative New 61.4-Mile, 20-Inch-Diameter SFPP Pipeline	Anticipated Unintentional Releases Over 50-Year Project Life – Any 1-Mile Section of Alternative New 61.4-Mile, 20-Inch-Diameter SFPP Pipeline
>1 (42)	0.1689	8.45	0.138
>5 (210)	0.1289	6.45	0.105
>10 (420)	0.1075	5.36	0.088
>50 (2,100)	0.0675	3.38	0.055
>100 (4,200)	0.0512	2.56	0.042
>500 (21,000)	0.0299	1.50	0.024
>1,000 (42,000)	0.0236	1.18	0.019
>5,000 (210,000)	0.0083	0.41	0.007
>10,000 (420,000)	0.0042	0.21	0.003

Table D.2-11. Anticipated Number of Pipeline Unintentional Releases Over 50-Year Project Life, Comparison of Project Alternatives.

	Proposed Project	Existing Pipeline ROW Alternative	No Project Alternative
Consequence	(70-mile, 20-inch diameter, new, 200,000 bpd capacity)	(61.4-mile, 20-inch diameter, new, 200,000 bpd capacity)	(61.4 mile, 14-inch diameter, 1967 construction, 150,000 bpd capacity)[1]
Injuries, regardless of severity	2.4	2.1	2.1
Injuries requiring hospitalization, causing loss of consciousness, or preventing discharge of normal duties the day following the incident	0.53	0.46	0.46
Fatalities	0.14	0.13	0.13
All Unintentional Releases (regardless of volume), in barrels (gallons)	10.1	8.84	13.8
Small Unintentional Release ≥1 (42)	9.63	8.45	12.77
≥5 (210)	7.35	6.45	8.35
≥10 (420)	6.12	5.36	6.63
≥50 (2,100)	3.86	3.38	3.98
Medium Unintentional Release ≥100 (4,200)	2.92	2.56	3.11
≥500 (21,000)	1.71	1.50	1.80
Large Unintentional Release ≥1,000 (42,000)	1.34	1.18	1.31
≥5,000 (210,000)	0.47	0.41	0.32
Very Large Unintentional Release ≥10,000 (420,000)	0.24	0.21	0.19

1 The anticipated numbers of unintentional releases, injuries, and fatalities from the No Project Alternative do not include any impacts associated with releases from additional refined petroleum product shipments by train or rail transportation. Other studies have shown that the frequency of unintentional releases from these transport modes is three to four times higher than for pipelines; the frequency of injuries, regardless of severity, was roughly 30 times higher; and that the frequency of fatalities was roughly 50 times higher for a mix of rail and truck transportation than for similar volumes being transported via pipeline.

Table D.2-12. Anticipated Number of Pipeline Unintentional Releases Over 50-Year Project Life, Comparison of Project Alternatives, Any One-Mile Segment of Line.

	Proposed Project	Existing Pipeline ROW Alternative	No Project Alternative
Consequence on Any One-Mile Segment	(70-mile, 20-inch diameter, new, 200,000 bpd capacity)	(61.4-mile, 20-inch diameter, new, 200,000 bpd capacity)	(61.4 mile, 14-inch diameter, 1967 construction, 150,000 bpd capacity)[1]
Injuries, regardless of severity	0.034	0.034	0.034
Injuries requiring hospitalization, causing loss of consciousness, or preventing discharge of normal duties the day following the incident	0.0075	0.0075	0.0075
Fatalities	0.0020	0.0020	0.0020
All Unintentional Releases (regardless of volume), in barrels (gallons)	0.144	0.144	0.224
Small Unintentional Release			
≥1 (42)	0.138	0.138	0.208
≥5 (210)	0.105	0.105	0.136
≥10 (420)	0.088	0.088	0.108
≥50 (2,100)	0.055	0.055	0.065
Medium Unintentional Release			
≥100 (4,200)	0.042	0.042	0.050
≥500 (21,000)	0.024	0.024	0.029
Large Unintentional Release			
≥1,000 (42,000)	0.019	0.019	0.021
≥5,000 (210,000)	0.007	0.007	0.005
Very Large Unintentional Release			
≥10,000 (420,000)	0.003	0.003	0.003

1 See Note 1, Table D.2-11

- 25% of the release volumes represented less than 0.14% of the volume between adjacent block valves.
- 50% of the release volumes represented less than 0.75% of the volume between adjacent block valves.
- 75% of the release volumes represented less than 4.6% of the volume between adjacent block valves.
- 80% of the release volumes represented less than 8.5% of the volume between adjacent block valves.
- 90% of the release volumes represented less than 28% of the volume between adjacent block valves.
- Only 6.4% of the total number of incidents resulted in release volumes which were greater than 50% of the volume between adjacent block valves.
- Only 4.6% of the total number of incidents resulted in release volumes which were greater than the volume between adjacent block valves.

There are three components that affect releases from a ruptured pipeline (1) continued pumping, (2) fluid decompression (because the pipeline is under high pressure), and (3) drain down (of the pipeline content based on gravity). The actual effect of each release volume component was impossible to evaluate with the data available. As a result, the values presented above represent the effects of all release volume components. As indicated, neglecting all other release volume components, reduced spacing between block valves could have directly affected release volumes in a maximum of only 4.6% of the incidents.

Often, when release volumes are being evaluated, the fact that a pipeline is a closed system is overlooked. To appreciate this phenomenon, a basic understanding of drain down release volumes is useful. Normally, when a release occurs, air must enter the pipeline to displace the fluid. (This is somewhat similar to turning a water container upside down; the water would release relatively slowly as air bubbles into the container to displace it. If however, a hole is made in the top of the container to allow air to enter, water will flow readily, since air will be available to displace the water.) In rolling hills, natural siphons are created along a pipeline. These natural siphons prevent a large portion of the pipeline volume from being released. However, in terrain with significant elevation changes, a large vacuum can be pulled on the fluid at the crest of a closed system. This vacuum is equivalent to the weight of the vertical column of the pipe's contents. For refined petroleum products, with relatively low vapor pressures, they simply vaporize within the segments of pipe with pressures less than the fluid vapor pressure. As this occurs, the pipe contents are allowed to flow from the release. In the analyses, an average gasoline mixture was assumed. The vapor pressure would cause the gasoline to vaporize when there is an elevation difference of 10 ft. Therefore, any fluid in the pipe that is less than 10 ft above the location of the release would not be released. At elevations greater than 10 ft above the release, vaporization will occur, allowing fluid to escape.

D.2.1.6 Environmental Setting: Proposed Project

This section describes the engineering features of each of the seven segments of the Proposed Project.

Segment 1 (MP 0–6.1) – Contra Costa County and Carquinez Strait

Segment 1 of the proposed pipeline would be 6.3 miles long. Except for the 0.45-mile section of pipeline near a residential neighborhood at MP 2.0 to 2.3, Segment 1 would be located in primarily uninhabited rural and industrial areas. Except for the roughly 1.1-mile portion beneath the Carquinez Strait, the route is relatively easily accessible from nearby surface streets. A detailed route description for each segment is provided in Section B.3.1.

The pipe specifications for this segment are summarized in Table D.2-13. The specifications below are for new pipe, except for the section of existing 14-inch-diameter seamless pipe that will be used to cross the Carquinez Strait (MP 5.0–6.1). The Carquinez Strait segment of the existing 14-inch pipeline was constructed and began operation in 1967.

Table D.2-13. Pipe Specifications for Proposed Pipeline, Segment 1 (MP 0–6.1)

Begin Milepost	End Milepost	Location	Specification (See Note 1)
0.00	0.30	Begin pipeline	20-inch O.D., 0.375" W.T., API 5L-X60, ERW, Pritec
0.30	0.50	Walnut/Grayson Creeks	20-inch O.D., 0.500" W.T., API 5L-X60, ERW, Pritec
0.50	4.75	Contra Costa County	20-inch O.D., 0.375" W.T., API 5L-X60, ERW, Pritec
4.75	5.02	Carquinez Strait	14-inch O.D., 0.375" W.T., API 5L-X60, ERW, Pritec
5.02	6.14	Carquinez Strait	14-inch O.D., 0.375" W.T., API 5L GRB, Seamless, Somastic Coating w/1.5" concrete, completed in 1967
6.14	6.25	Carquinez Strait	14-inch O.D., 0.375" W.T., API 5L-X60, ERW, Pritec
6.25	6.33 (MP 6.12)[2]	Carquinez Strait	20-inch O.D., 0.375" W.T., API 5L-X60, ERW, Pritec

Notes:
[1] O.D. = outside pipe diameter
W.T. = pipe wall thickness
API 5L = American Petroleum Institute, Specification 5L, covers the manufacturing of line pipe
X60 = pipe with a minimum specified yield strength of 60,000 psi
GRB = pipe with a minimum specified yield strength of 35,000 psi
ERW = pipe with a longitudinal weld seam manufactured by the electric resistance welded process
Seamless – pipe manufactured without a longitudinal weld seam
Pritec = brand name for external corrosion coating. It is worth noting that the California Study found that pipe coated with this material experienced the lowest unintentional release rate for releases caused by external corrosion of all of the identified coatings. The statistical analysis indicated, though, that the primary differences were caused by operating temperature and pipe age.
[2] The total segment length is different from mileposts because of SFPP's reroutes within the segment.

This segment of the proposed pipeline would contain four water crossings — the existing Carquinez Strait crossing and three new crossings. Two of the new crossings would be installed using horizontal directional-drilled techniques. The third would be an open-cut crossing. The lengths and locations of all proposed water crossings are presented in Table B-3. Section D.8.1.2 presents tables of water crossings in each segment.

The Applicant has proposed three remotely operated block valves (also called motor operated valves or MOVs) within Segment 1. The first would be located at the start of the pipeline. The second two would be located on the north and south shores of the Carquinez Strait. These valves would be co-located with the pig launcher/receiver stations at the transitions between 20-inch-diameter pipe and 14-inch-diameter pipe. The spacing between these MOVs is 4.75 and 1.5 miles. The next downstream valve (manually operated) is proposed at MP 15.15 within Segment 2, 9 miles downstream of the MP 6.25 MOV.

Table D.2-14. Valves Along Proposed Pipeline Route, Segment 1 (MP 0–6.1)

Valve No.	Location (MP)	Valve Type	Location	Jurisdiction
1	0.00	20-inch MOV	SFPP Concord Station, 20-inch Launcher	Contra Costa County
2	4.75	20-inch MOV	Rhodia Plant, 20-inch and 14-inch Launcher/Receiver Station (s/o Carquinez Strait)	City of Martinez
3	6.25	20-inch MOV	Benicia Industries, 14-inch and 20-inch Launcher/Receiver Station (n/o Carquinez Strait)	City of Benicia

The elevation profile for Segment 1 indicates that the terrain is generally flat (see Figure B-3 for an overall ground profile of the proposed pipeline). The pipeline would traverse two hills, one reaching an elevation of 80 feet and the other reaching an elevation of 40 feet. Additionally, the existing pipeline drops to an elevation of –60 feet as it passes beneath the Carquinez Strait.

Phase 1 Carquinez Strait Crossing

SFPP proposes to use its existing 14-inch pipeline as the means of crossing the Carquinez Strait until such time as a single HDD is proven feasible. (The HDD would be completed in Phase 2; see below.) SFPP has evaluated the type and pressure rating of the existing pipe, its integrity, pipeline hydraulics, and potential impacts to the proposed upgrades at Concord Station. The 6,000-foot portion of the 14-inch existing pipeline beneath the Carquinez Strait is 0.375-inch wall thickness, seamless, API 5L Grade B pipe, rated for a maximum operating pressure of 1,350 psig. The Applicant has reported that recent internal “smart” pig inspection results, evaluation of the cathodic protection data, and underwater visual inspection have indicated that there are no pipe integrity issues with this portion of the existing pipeline.

In 1992, SFPP elected to place additional cover over portions of the existing line by placing 4-inch quarry rock into the water above the line using a clamshell rig mounted on a barge. After the rock was placed, a bathymetric survey was performed to confirm adequate placement of the rock. More recent surveys have indicated that the existing pipe crossing depth of cover is less than current CSLC requirements. It is assumed that a similar procedure and similar material would be used to return the pipeline cover, in compliance with anticipated CSLC lease conditions.

To accommodate the use of the existing pipeline, at the northwest limit of the Rhodia facility, a permanent above-ground pig launcher/receiver station is proposed. This facility would be constructed to enable pigs to be received from the upstream 20-inch pipe. The facility would also be used to launch pigs into the downstream 14-inch pipe segment. The pig launcher/receiver station would be contained within an approximately 40-foot by 75-foot fenced area and would include necessary above-ground piping and valving to allow passage of normal maintenance pigs and internal inspection tools (aka “smart pigs”). The entire area would be curbed for containment.

From the pig launcher/receiver station, approximately 750 feet of new 14-inch pipeline would be constructed to connect to the existing 14-inch pipeline, which would be used for the 6,000-foot crossing beneath the Carquinez Strait. On the north shore of the Carquinez Strait, the existing 14-inch pipeline would be connected to another new 14-inch pipeline segment, which would then continue for approximately 550 feet to a second proposed permanent above-ground pig launcher/receiver station. This station would be the same size or slightly larger but with the same configuration as the one proposed on the Rhodia property. It would be located at the point where the pipeline would transition back to the new 20-inch pipe.

Phase 2 Carquinez Strait Crossing

In the future, as hydraulic capacity of the proposed system is approached (estimated by SFPP at 10 to 12 years) and/or as HDD technology is enhanced, SFPP will pursue the installation of a new 20-inch pipe segment beneath the Carquinez Strait. This pipe would be installed using a single HDD. A subsequent CEQA analysis would be performed at the time the new HDD crossing is proposed.

Segment 2 (MP 6.1–17.6) – Benicia and I-680 Frontage

A detailed route description for each segment is provided in Section B.3.1. Generally, the route parallels the access road, located on the West side of and parallel to, the 680 Freeway. The entire segment is proposed to be constructed in rural areas. This segment would consist of 11.3 miles of new 20-inch pipe, as summarized below.

Table D.2-15. Pipe Specifications for Proposed 11.3-Mile, 20-Inch-Diameter Pipeline, Segment 2 (MP 6.1–17.6)

Begin Milepost	End Milepost	Location	Specification
6.12	17.55	Benicia / Solano County	20-inch O.D., 0.375” W.T., API 5L-X60, ERW, Pritec

The proposed route of Segment 2 would involve 15 water crossings — one HDD crossing, three bored and jacked crossings, and 11 open cut crossings (see Table B-3 and Section D.8.1.2).

Segment 2 would contain one manual block valve at the point where the pipeline would cross beneath the 680 Freeway, at MP 15.15. The proposed manual block valve is readily accessible, located off of Lopes Road, near 680, approximately 1.1 miles from the nearest freeway exit. The manual block valve within this segment is 9 miles from nearest upstream valve, and the MOV is located at the pig launcher/receiver, on the north shore of the Carquinez Strait. The nearest downstream valve is a check valve[3], located at MP 20.10, 4.95 miles downstream. Table D.2-16 below summarizes the information for this valve.

Table D.2-16. Valves Along Proposed Pipeline Route, Segment 2 (MP 6.1–17.6)

Valve No.	Location (MP)	Valve Type	Location	Jurisdiction
4	15.15	20-inch Manual	Private, w/o Lopes (@ 680 crossing)	Solano County

The elevation profile of Segment 2 shows a gradually decreasing elevation. From the north side of the Carquinez Strait, the elevation increases to 45 feet, over about 8.5 miles. Then the profile gradually slopes down to 5 feet. At the very end of Segment 2, the pipeline elevation rises to 25 feet as it climbs a small hill.

[3] A check valve (also called a “gate valve”) prevents product from flowing backward in the pipe. When pumping pressure drops, a flap within the pipe closes automatically.

Segment 3 (MP 17.6–24.5) – Cordelia

Segment 3 of the proposed pipeline would be 6.9 miles in length. The pipe specifications for Segment 3 are detailed below. This segment would be constructed entirely from new 20-inch-diameter pipe. As indicated, heavier wall pipe is proposed for the major water crossings.

Table D.2-17. Pipe Specifications for Proposed Pipeline, Segment 3 (MP 17.6–24.5)

Begin Milepost	End Milepost	Location	Specification
17.55	19.10	Benicia / Solano County	20-inch O.D., 0.375" W.T., API 5L-X60, ERW, Pritec
19.10	19.25	Cordelia Slough	20-inch O.D., 0.500" W.T., API 5L-X60, ERW, Pritec
19.25	23.18	Solano County	20-inch O.D., 0.375" W.T., API 5L-X60, ERW, Pritec
23.18	23.40	Ledgewood Creek	20-inch O.D., 0.500" W.T., API 5L-X60, ERW, Pritec
23.40	24.50	Suisun City / Fairfield	20-inch O.D., 0.375" W.T., API 5L-X60, ERW, Pritec

Ten water crossings are proposed for Segment 3, including: 2 horizontal directional-drilled crossings 5 bored and jacked crossings, and 3 open cut crossings (see Table B-3 and Section D.8.1.2).

Segment 3 would contain one check valve, near MP 20.1. This valve is approximately 4.82 miles from the nearest upstream valve at MP 15.15 (manual block valve). It is 4.65 miles from the nearest downstream valve — a MOV at MP 24.75.

Table D.2-18. Valves Along Proposed Pipeline Route, Segment 3 (MP 17.6–24.5)

Valve No.	Location (MP)	Valve Type	Location	Jurisdiction
5	20.10	20-inch Check	Private, e/o kennel & w/o train tunnel	Solano County

The profile of this segment is relatively flat. The elevation generally varies between 5 and 25 feet, with an isolated peak of 80 feet, near the upstream portion of the segment. This segment is located primarily in remote rural areas, with somewhat difficult access for emergency response.

Segment 4 (MP 24.5–30.7) – Fairfield / Suisun City

A detailed route description for this segment is provided in Section B.3.1. Generally, this segment of the pipeline would travel through a populated, urban and suburban area for about four miles, from MP 24.5 to 28.4. This area contains housing subdivisions, a high school, an elementary school, a daycare center, and four churches. The elevation profile of this segment is relatively flat, with a fairly steady increase from 5 to 80 feet.

Segment 4 would be constructed entirely out of new 20-inch-diameter pipe. The total pipeline segment length would be 6.2 miles. The proposed pipe specifications are detailed in Table D.2-19.

Segment 4 contains four proposed water crossings. One is proposed to be open cut. The other three are proposed to be installed using the bore and jack technique (see Table B-3 and Section D.8.1.2).

Table D.2-19. Pipe Specifications for Proposed Pipeline, Segment 4 (MP 24.5–30.7)

Begin Milepost	End Milepost	Location	Specification
24.5	30.7	Suisun City / Fairfield	20-inch O.D., 0.375” W.T., API 5L-X60, ERW, Pritec

One MOV is proposed within Segment 4 (MP 24.75). The proposed valve would be located at the point where the pipeline would enter the residential area. This valve would be 4.71 miles from the nearest upstream valve (check valve at MP 20.1). It is 9.7 miles from the nearest downstream valve, a manual block valve at MP 34.75.

Table D.2-20. Valves Along Proposed Pipeline Route, Segment 4 (MP 24.5–30.7)

Valve No.	Location (MP)	Valve Type	Location	Jurisdiction
6	24.75	20-inch MOV	Private, at Broadway w/o UPRR	City of Fairfield

Segment 5 (MP 30.7–65.1) – Solano and Yolo Counties Agricultural Area

This segment of pipeline passes through mostly vacant or farmland, with occasional individual homes, but no large communities. The total length of pipeline in the proposed Segment 5 would be 34.32 miles. This segment would be constructed from new 20-inch pipeline, as shown in Table D.2-21. As indicated, all major water crossings would be constructed using heavier wall pipe.

Segment 5 would contain 29 water crossings, including 5 HDD crossings and 24 bored and jacked crossings (see Table B-3 and Section D.8.1.2).

Table D.2-21. Pipe Specifications for Proposed Pipeline, Segment 5 (MP 30.7–65.1)

Begin Milepost	End Milepost	Location	Specification
30.70	40.62	Suisun City / Fairfield	20-inch O.D., 0.375” W.T., API 5L-X60, ERW, Pritec
40.62	40.77	Ulatis Creek	20-inch O.D., 0.500” W.T., API 5L-X60, ERW, Pritec
40.77	42.75	Solano County	20-inch O.D., 0.375” W.T., API 5L-X60, ERW, Pritec
42.75	42.95	Hass Slough	20-inch O.D., 0.500” W.T., API 5L-X60, ERW, Pritec
42.95	57.69	Solano / Yolo County	20-inch O.D., 0.375” W.T., API 5L-X60, ERW, Pritec
57.69	57.85	Putah Creek	20-inch O.D., 0.500” W.T., API 5L-X60, ERW, Pritec
57.85	59.65	Yolo County	20-inch O.D., 0.375” W.T., API 5L-X60, ERW, Pritec
59.65	59.80	Channel	20-inch O.D., 0.500” W.T., API 5L-X60, ERW, Pritec
59.80	61.94	Yolo County	20-inch O.D., 0.375” W.T., API 5L-X60, ERW, Pritec
61.94	62.08	Willow Slough	20-inch O.D., 0.500” W.T., API 5L-X60, ERW, Pritec
62.08	65.10	Yolo County	20-inch O.D., 0.375” W.T., API 5L-X60, ERW, Pritec

Four manual block valves are proposed for Segment 5. All four valves would be manual and located in rural areas. The first valve (MP 34.75) would be located near the intersection of Meridian Road and Hay Road. The second valve (MP 44.6) would be located on an old railroad ROW near Binghamton Road. The third valve (MP 54.4) would be located off of Road 106. The fourth valve (MP 61.9) would be located near Freeway 80, only 0.15 miles from the nearest freeway exit. The first valve is roughly 10 miles from the nearest upstream valve, the MOV proposed at MP 24.75. The subsequent valves are 9.86, 9.8, and 7.71 miles apart. The MP 61.9 valve is 3.6 miles from the nearest downstream valve, a MOV at MP 65.5.

Table D.2-22. Valves Along Proposed Pipeline Route, Segment 5 (MP 30.7–65.1)

Valve No.	Location (MP)	Valve Type	Location	Jurisdiction
7	34.75	20-inch Manual	Private, s/w Meridian and Hay	Solano County
8	44.6	20-inch Manual	Private, near Binghamton	Solano County
9	54.4	20-inch Manual	Private, near Rd 106	Yolo County
10	61.90	20-inch Manual	Private, w/o Willow Slough	Yolo County

From an initial elevation of about 90 feet, the pipeline profile rises to 110 feet, before beginning a gradual decent. From 110 feet, the elevation decreases to 20 feet over a horizontal distance of 7.5 miles. The remainder of this segment traverses fairly level terrain.

Segment 6 (MP 65.1–69.9) – West Sacramento

From MP 65.3 through the end of the pipeline, the pipeline would follow a route near urban neighborhoods and industrial areas, including campgrounds, RV parks, housing subdivisions, and two churches. The elevation of the terrain of the proposed route is fairly level.

The Applicant-proposed pipe specifications for Segment 6, noted below, are for new 20-inch pipe. This segment would be 4.74 miles long.

Segment 6 would contain two HDD water crossings, including an 800 foot crossing beneath Washington Lake. It would contain three valves: two MOVs and one manual block valve. The first MOV would be located 3.6 miles downstream of the nearest upstream manual block valve at MP 61.9. The next two valves (one manual block valve and one MOV) are spaced 3.8 and 0.54 miles apart.

Table D.2-23. Pipe Specifications for Proposed Pipeline, Segment 6 (MP 65.1–70)

Begin Milepost	End Milepost	Location	Specification
65.10	65.20	Yolo County	20-inch O.D., 0.375” W.T., API 5L-X60, ERW, Pritec
65.20	65.36	Toe Drain	20-inch O.D., 0.500” W.T., API 5L-X60, ERW, Pritec
65.36	69.84	West Sacramento	20-inch O.D., 0.375” W.T., API 5L-X60, ERW, Pritec

Table D.2-24. Valves Along Proposed Pipeline Route, Segment 6 (MP 65.1–70)

Valve No.	Location (MP)	Valve Type	Location	Jurisdiction
11	65.50	20-inch MOV	Private, e/o Toe Drain	City of West Sacramento
12	69.30	20-inch Manual	Private, south end of S. River Rd	City of West Sacramento
13	69.84	20-inch MOV	SFPP Sacramento Station, 20-inch Receiver	City of West Sacramento

Segment 7 – Wickland Connection

In addition to the proposed route, SFPP proposes constructing a new 12-inch-diameter pipeline to supply fuel to Wickland from SFPP’s proposed 20-inch-diameter pipeline to the Sacramento International Airport. Construction of this segment would be concurrent with construction of the main line pipeline. The Wickland Connection would allow connection of SFPP’s pipeline via a meter station at a location north of West Capitol Avenue in West Sacramento. The proposed 4,100-foot, 12-inch pipeline connection to Wickland would begin at approximate MP 65.6. A new meter station would be located at the tie-in location. No valves are proposed for this segment, and there are no proposed water crossings. The length of this segment would be 0.8 miles. The route would parallel industrial areas. The terrain of the proposed route is relatively level.

Proposed Terminal Modifications

Upgrades to SFPP's existing Concord and Sacramento Stations would be required to connect and operate the new pipeline. These upgrades would occur within the existing facility boundaries and would include the installation of piping, fittings, valves, and other equipment that would be necessary to connect the new pipeline to the existing facilities. The same SFPP specifications, codes and regulations that dictate material purchase, construction, inspection, testing, and maintenance for the pipeline would apply to upgrade work within the stations.

Concord Station. Upgrades to the Concord Station would include tank suction piping, surge system and surge pumps, modifications to existing shipping pumps, new pig launcher, and a new meter and prover. Modifications to existing electrical instrumentation and controls would be required to facilitate the increased pipeline size and to maintain leak detection.

Sacramento Station. Upgrades at the Sacramento Station would include a new pig receiver, a new product meter for leak detection, and upgrades to existing electrical instrumentation and controls.

D.2.1.7 Environmental Setting: Existing Pipeline ROW Alternative

The Existing Pipeline ROW Alternative would include the construction of a new 20-inch line, essentially parallel to the existing route of SFPP's existing 61.4-mile line from Concord to West Sacramento. It would be constructed nearly entirely within the UPRR ROW. This route would cross approximately 21 major waterbodies and more than 15 other small streams and canals. These crossings would range from 25- to 50-foot creek or canal crossings to a 6,925-foot crossing of the Carquinez Strait. The crossing techniques would be similar to the proposed pipeline methods using a horizontal directional drill (HDD), slick bore, cased bore, or open cut construction methods

Two mitigation segments are suggested for the Existing Pipeline ROW Alternative, one (EP-1) suggested to reduce biological resources impacts and one (EP-2) to reduce land use impacts.

D.2.1.8 Environmental Setting: No Project Alternative

As described in Section C.3, the No Project Alternative would likely include improvements to SFPP's existing pipeline system, and the use of trucks and/or trains to serve remaining demand for product transport. The impacts of the No Project Alternative are addressed in Section D.2.5.

D.2.2 Applicable Regulations, Plans, and Standards

This section describes the Pipeline Safety and Risk of Accidents aspects of the applicable laws, regulations, and standards for the Proposed Project and the identified alternatives.

D.2.2.1 Federal

Interstate and intrastate hazardous liquid transportation by pipeline and rail fall under the jurisdiction of the U.S. Department of Transportation, Research and Special Programs Administration, Office of Pipeline Safety (DOT). Hazardous liquid pipelines must conform with the design, construction, testing, operation and maintenance regulations contained in Title 49 Code of Federal Regulations (CFR) Part 195, "Transportation of Hazardous Liquids by Pipeline," as authorized by the Hazardous Liquid Pipeline Safety Act of 1979 (49 U.S.C. 2004). However, the DOT does not issue a construction permit or conduct a plan check for all pipeline projects.

49 CFR 194 prescribes the federal requirements for response plans for onshore oil pipelines. Other relevant federal requirements applicable to the transportation of hazardous liquids by pipeline are contained in 40 CFR Parts 109, 110, 112, 113, and 114, which pertains to the need for "Oil Spill Prevention Control & Countermeasures (SPCC) Plans" and Public Law 101-380 (H.R.), promulgated in response to the Oil Pollution Act (OCA) of 1990.

Overview of the 49 CFR 190, Pipeline Safety Program Procedures

This part prescribes procedures that are used by the DOT relative to their duties regarding natural gas and hazardous liquid pipeline safety.

Overview of the 49 CFR 195, Transportation of Hazardous Liquids by Pipeline

Part 195.3. This section incorporates many of the applicable national safety standards of the following organizations.

- American Petroleum Institute (API).
- American Society of Mechanical Engineers (ASME).
- American National Standards Institute (ANSI).
- American Society for Testing and Materials (ASTM).
- Manufacturers Standardization Society of the Valve and Fittings Industry (MSS).

Part 195.6. This section was recently added to the regulation (December 21, 2000). It defines Unusually Sensitive Areas (USA's). USA's are drinking water or ecological resource areas that are unusually sensitive to environmental damage from a hazardous liquid pipeline release, including:

- Certain drinking water resources (e.g., community water systems, certain aquifers, sole source aquifers, etc.).
- Certain ecological resources (e.g., critically imperiled species, multi-species assemblage area, threatened or endangered species, etc.).
- Alternative drinking water sources.

Part 195.50 to 54. These sections require reporting of the following incidents:

- Incident which resulted in an explosion or fire not intentionally set by the operator.
- Effective January 1, 2002, the reportable release volume was reduced to any release of 5 gallons or more of hazardous liquid or carbon dioxide, unless the release resulted from maintenance activity, in which case the reportable release volume was 5 barrels (210 gallons) or more. (Prior to January 1, 2002, the reportable release volume was 2,100 gallons or more of liquid for any unintentional release.)
- Death of a person.
- Effective January 1, 2002, an accident resulting in an injury necessitating hospitalization must be reported. (Prior to January 1, 2002, an accident resulting in serious injury to any person resulting in loss of consciousness, necessity to carry the individual from the scene, medical treatment, or disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the incident was required to be reported.)
- Damage to property of operator, or others, or both, greater than $50,000 (including the cost of cleanup and recovery, property damage, and lost product).

Part 195.55 and 56. These sections require reporting of the following safety related conditions, unless they are excluded from reporting. The pipeline operator is required to file a written report with the DOT within five working days of the time in which the operator first determined that the condition exists.

- General corrosion which has reduced the wall thickness to less than that required for the maximum operating pressure or localized corrosion which could result in a release.
- Unintended movement or abnormal loading of a pipeline by environmental causes (e.g., earthquake, landslide, flood) that impairs its serviceability.
- Any material defect or physical damage that impairs the serviceability of a pipeline.
- Any malfunction or operating error that causes the pressure of a pipeline to rise above 110% of the maximum operating pressure.
- A release in a pipeline that constitutes an emergency.
- Any safety related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator) a 20% or more reduction in operating pressure or shutdown of pipeline operation.

The following safety related conditions are excluded from reporting:

- A safety related condition that is more than 220 yards from a human occupancy or outdoor assembly place (except that reports are required within railroad rights-of-way, paved roadways, or where an incident could reasonably be expected to pollute any stream, river, lake, reservoir, or other waterbody).
- Any safety related condition which is corrected by repair or replacement in accordance with applicable safety standards before the report deadline (except that reports are required for general corrosion on all lines and localized corrosion on unprotected lines).

Overview of 40 CFR Parts 109, 110, 112, 113, and 114

The Oil Spill Prevention Control & Countermeasures (SPCC) covered in these regulations apply to oil storage and transportation facilities and terminals, tank farms, bulk plants, oil refineries, and production facilities, as well bulk oil consumers such as apartment houses, office buildings, schools, hospitals, farms, and State and Federal facilities.

Part 109. Establishes the minimum criteria for developing oil removal contingency plans for certain inland navigable water by State, local, and regional agencies in consultation with the regulated community (oil facilities).

Oil Pollution Act of 1990 (OPA). Public Law 101-380 (H.R.): August 18, 1990

The Oil Pollution Act of 1990, together with the Oil Pollution Liability and Compensation Act of 1989, builds upon Section 311 of the Clean Water Act (CWA) to create a single federal law providing cleanup authority, penalties, and liability for oil pollution. The bill creates a single fund to pay for removal of and damages from oil pollution. This new fund replaces those created under the Trans-Alaska Pipeline Act, Deep Water Port Act of 1974, and Outer Continental Shelf Lands Act, and supersedes the contingency fund established under Section 311 of CWA.

The Oil Spill Compensation Fund will be available, up to a limit of $1 billion per incident, for all removal costs and compensatory damages. The Act provides for liability and availability of the fund to pay removal costs and compensation in case of discharges of oil. It adopts the standard of liability under Section 311 for liability of dischargers for cleanup costs — strict, several, and joint liability. The law establishes financial liability of all oil facility operators including pipelines. The OPA provides for financial liability related to land-based pipelines, but only as they relate to "discharges of oil, unto or upon the navigable waters or adjoining shorelines . . . ."

The Act affirms the rights of States to protect their own air, water, and land resources by permitting them to establish State standards which are more restrictive than federal standards. More stringent State laws are specifically preserved. Section 106 explicitly preserves authority of any State to impose its own requirements or standards with respect to discharges of oil within each State.

As a result of this legislation, 49 CFR 194 was codified to require operators to prepare oil spill response plans for onshore oil (including petroleum, fuel oil, etc.) pipelines. The intent of these regulations is to reduce the environmental impact of oil discharged from onshore pipelines. The operator is required to determine the worst case discharge in each response zone and meet specified criteria. The completed plan must be submitted to the DOT Pipeline Response Plans Officer for review and approval.

D.2.2.2 State

The Pipeline Safety Division of the Office of the State Fire Marshal acts as the agent for the DOT and exercises exclusive regulatory and enforcement authority over intrastate pipelines within California. The Pipeline Safety Division also acts as the agent for the DOT in implementing the federal regulations, as those regulations apply to interstate pipeline located within the State. The Division also enforces California State regulations, which impose additional requirements on the State's intrastate pipeline operators — beyond the federal requirements.

The California State regulations are includes in the California Government Code, Sections 51010-51019.2. Some of the requirements that exceed federal regulations include the following:

- Every pipeline over 10 years of age and not provided with effective cathodic protection must be hydrostatically tested every three years, except for those lines on the list of higher risk lies, which must be hydrostatically tested annually.
- Every pipeline over 10 years of age and provided with effective cathodic protection must be hydrostatically tested every five years, except for those lines on the list of higher risk lies, which must be hydrostatically tested every two years.
- Piping within a refined products bulk loading facility served by pipeline must be pressure tested every five years if cathodically protected, or every three years if not effectively cathodically protected.
- Hydrostatic tests conducted in compliance with the State regulations must be certified by an independent testing firm, approved by the Pipeline Safety Division.

D.2.2.3 Industry Standards

There are a number of industry codes and standards used in the design, construction, operation, and maintenance of hazardous liquid pipelines. These standards and codes have been promulgated by the following:

- American Petroleum Institute.
- American Society of Mechanical Engineers.
- National Association of Corrosion Engineers.
- National Fire Protection Association.
- American National Standards Institute.

D.2.3 Environmental Impacts and Mitigation Measures for the Proposed Project

This section discusses potential operational safety and risk of accidents impacts associated with the routine and upset conditions related to construction, operation, and abandonment of the Proposed Project and identified alternatives. Information is presented outlining significance criteria, potential hazard scenarios, the probabilities of various incidents occurring, and the consequences associated with the hazard scenarios. The impacts and proposed mitigation measures to minimize or eliminate the probability or severity of each general category of impact are also presented.

D.2.3.1 Introduction

Evaluating the significance of impacts of a proposed project is a subjective process. It depends on the determination of an acceptable level of risk to the environment and an acceptable level of risk to humans. The potential impacts and probability of occurrence of incidents associated with the proposed pipeline are presented in Sections D.2.3.3 through D.2.3.10. Accident statistics for each pipeline segment are presented in Appendix 2. The impacts associated with alternatives are discussed in Sections D.2.4 and D.2.5.

D.2.3.2 Definition and Use of Significance Criteria

The study area for the Proposed Project and identified alternatives includes the land and population surrounding the proposed and alternative pipeline, rail, and truck transportation routes. The CSLC has determined that an adverse impact related to pipeline safety would be considered significant and would require additional mitigation if:

- The design of the pipeline and related facilities is shown to be expected to result in a rupture or failure that would cause exposure hazards to the public from fire, explosion, or release of chemical or product materials, as supported by historical performance of similarly designed pipelines.

This section considers the likelihood that the Proposed Project, a new, approximately 70-mile, 20-inch pipeline, will have accidents resulting in leaks, spills, fires, or explosions. In the event of an unintentional release, impacts could affect public health and safety; they may also affect other resources within the environment. The significance of impacts on environmental issue areas is addressed in other parts of Section D. For example, the impacts of a product spill on wildlife resources are identified in Section D.4, Biological Resources; the potential impacts on water resources are discussed in Section D.8. This section, Section D.2, evaluates impacts on public safety and also presents the data on unintentional pipeline releases, which is the basis for the environmental analysis in other disciplines.

To the extent possible, four steps have been undertaken to assess the safety impacts and the risk of upset associated with the Proposed Project and the identified alternatives:

1. Describe the range of potential hazards associated with the project;
2. Estimate the likelihood of the hazards occurring;
3. Describe the range of consequences of the hazards, should they occur; and
4. Determine the significance of overall risk based on the probability of occurrence and the severity of consequences.

Based on these steps and industry practice in evaluating accident risk, this analysis will consider the following pipeline impacts to human life as significant:

- Small level of public risk, with at most a few minor injuries at a likelihood of greater than once each year,
- Major level of public risk, with between 1 and 10 severe injuries at a likelihood of up to once in 10,000 years (greater than a one in 200 chance of occurring during the 50-year project life), or
- Severe level of public risk, with between 11 and 100 severe injuries or between 1 and 10 fatalities at a likelihood of up to once in a million years (greater than a one in 20,000 chance of occurring during the 50-year project life).

Based on these criteria, in the following sections, significant (Class I) impacts have been identified for the Proposed Project. These significant impacts also apply to the Existing Pipeline ROW Alternative. However, it is important to note that the No Project Alternative (including continued use of the existing 14-inch pipeline and the use of trucks and trains) would also have significant impacts, and these impacts are found to be more severe than those of the Proposed Project. The reader should not necessarily conclude that the Proposed Project poses a higher risk to the public and the environment simply because significant impacts have been identified.

In the remainder of Section D.2.3, the operational safety and risk of accident impacts of all aspects of the Proposed Project will be presented. Impacts of pipeline construction are described in Section D.2.3.3. SFPP's proposed system of operation is described in Section D.2.3.4. The frequency and impacts of unintentional releases is presented in Sections D.2.3.5 to D.2.3.7. Section D.2.3.8 addresses the impacts of the Cordelia Mitigation Segment, and Sections D.2.3.9 and D.2.3.10 address station changes and abandonment, respectively. The Applicant has proposed specific design factors to enhance operational safety; these measures and the overall risk of accidents will also be presented. In each section, recommended mitigation measures are proposed. The likelihood of occurrence and significance of the consequences will also be described.

D.2.3.3 Impacts of Pipeline Construction

Impact S-1: Construction Activities Present Hazards to the Public and Construction Workers

Several separate construction impacts are described below; each is identified as a component of Impact S-1 (i.e., as Impact S-1.1, S-1.2, etc.).

In this section, the factors that could cause several different types of pipeline construction impacts are described. The likelihood of each event and the severity of the impacts is determined, and mitigation measures is proposed to reduce the likelihood and/or severity of these impacts. Finally, a conclusion regarding residual impact will be made, considering the effects of the proposed mitigation measures. Generally, impacts will only be presented as they relate to the general public. Impacts on construction worker impacts will be presented only where construction activities may also impact the public.

The impacts associated with pipeline construction and relevant design measures are presented in Table D.2-25. The construction impacts identified apply to the construction of all pipeline segments.

Table D.2-25. Pipeline Construction Impacts

Cause of Impact	Impact Designation and Effect
Construction within, along, or near existing roadways	Traffic collisions caused by poor signage, distraction by construction equipment, constrained roadway.
Severance of third party substructures during construction	Unintentional release or personal injury (primarily construction worker) caused by severing third party substructure(s).
Fire	Personal injury or property damage resulting from construction–caused fire.

Impact S-1.1: Construction Could Cause Traffic Collisions

Construction activities could create traffic hazards. (Potentially Significant, Class II)

Impact Discussion

During the construction of the pipeline within, along, or near existing roadways (both paved and unpaved), the motoring public could be exposed to additional traffic related risks. These risks could result from poor signage, driver distraction by construction equipment, or constrained roadways due to construction activity. This exposure may cause traffic accidents that could result in property damage, personal injury, or death, creating a potentially significant (Class II) impact.

Mitigation Measure for Impact S-1.1: Construction Could Cause Traffic Collisions

Mitigation Measure T-1b (in Section D.12, Traffic and Transportation), would reduce the likelihood and severity of these incidents.

Residual Impact. Implementation of Mitigation Measure T-1b would warn, control, and protect the public and construction workers. With the proposed mitigation, this impact would be less than significant (Class II).

Impact S-1.2: Severance of Third Party Substructures during Construction

Construction activities can damage other substructures, causing contamination, injury or death. (Potentially Significant, Class II)

Impact Discussion

During excavation operations, there is a risk of personal injury or death (primarily construction worker), environmental contamination, and/or property damage which could be caused by the striking or severance of existing substructures (e.g., power cables, foreign pipelines).

One California statute is included in Section 7110 of the Business and Professions Code relating to contractors. This statute imposes disciplinary action for failure of contractors to adhere to the State's "one call" regulations, among other things. Another California statute is included the California Government Code, Title 1, Division 5, Chapter 3.1 (Protection of Underground Infrastructure), and beginning with Section 4216. This statute provides the framework for the State's one-call system. It was adopted in September 1989. It requires every operator of an underground facility, except the California Department of Transportation, to become a member of, participate in, and share the costs of the one-call system. Anyone planning an excavation must notify the appropriate regional notification center (either Northern or Southern California) and mark the excavation area at least 2 days, but not more that 14 days prior to commencing excavation. The one-call system then notifies all operators of underground facilities within the area. The operators are required to mark the location of their facilities in the field before the excavation date. A civil penalty of up to $10,000 may be imposed on any operator or excavator who negligently violates this article. A civil penalty of up to $50,000 may be imposed on any operator or excavator who knowingly and willfully violates this article. Further, if an excavator fails to comply with the requirements, the excavator is liable for any claim for damages to the subsurface installation arising from the excavation. Underground facility owners forfeit their claims for damages from an excavator, should they fail to comply with these requirements.

Although this and similar one-call services have been very effective in reducing unwanted damage to existing facilities, third party damage still causes approximately one-half of all hazardous liquid incident consequences. As a result, additional measures should be incorporated to further reduce the likelihood and severity of an incident. Many of these actions have been recommended by the National Transportation Safety Board (NTSB, December 1997). Mitigation Measure S-1a is recommended.

Mitigation Measure for Impact S-1.2: Severance of Third Party Substructures during Construction

S-1a Minimize Effect on Other Underground Facilities. The Applicant shall monitor the construction contractor's compliance with existing State law, including the advance marking of all proposed excavations, the dates of all Underground Service Alert (USA) calls, and on-site meetings held with underground facility owners. The Applicant shall also require the construction contractor(s) to clear the right-of-way using a hand held line locator prior to excavation.

Should changes in the alignment be required, the Applicant shall ensure that the entire one-call notification process is repeated to ensure that any reroute is thoroughly investigated.

Prior to digging over, or within three feet of a known substructure, the Applicant shall require the construction contractor(s) to probe the area to positively locate the facility and measure the depth of the substructure; the Applicant shall also require the use of hand digging within two feet (horizontal and vertical) of any existing substructure and within five feet of any pedestal, closure, riser guard, pole, meter of other structure. When paralleling an existing underground facility, the facility shall be exposed every 50 feet to positively verify the location and depth of the line.

When boring or directionally drilling, the boring equipment shall be placed such that it is boring away from the majority of other underground facilities. When such facilities must be crossed, they shall be exposed to verify their location and depth. The results may require that the bore route or depth be changed to avoid potential damage to the existing facility.

If during the course of the work, unmarked pipelines are encountered, the Applicant shall take appropriate measures to identify the owner of the facility. This shall include, but is not limited to the following substructure research: USA notification; research of City, County, and State records; and communication with other utility owners in the area. If the owner of the facility cannot be determined, the proposed pipeline shall be lowered to avoid any conflict. If it is impossible to avoid an existing substructure of unknown ownership or use, the pipe contents shall be positively identified before any cutting of the substructure is allowed; this shall be done by tapping or other means. The substructure may not be cut or removed until a safe procedure for doing so has been developed; this procedure will vary, depending on the pipe contents and site conditions. Once the facility has been removed, the remaining ends shall be capped using the same construction techniques as the substructure's original construction to prevent leakage should the substructure be pressured. Cathodic protection tests shall also be conducted. If the facility is cathodically protected, a bonding cable shall be installed to maintain the integrity of the facility's cathodic protection system.

Residual Impact: With implementation of Mitigation Measure S-1a, Impact S-1.2 would be less than significant (Class II).

Impact S-1.3: Injury, Death or Property Damage from Construction Fire

Construction activities can cause fires, resulting in property damage, injury, or death. (Potentially Significant, Class II)

Impact Discussion

Personal injury, death, or property damage can result from construction-caused fires. Fires can be caused by welding, grinding, vehicle exhausts, sparks, etc. To minimize the risk of these incidents, in addition to compliance with OSHA requirements, Mitigation Measure S-1b should be employed.

Mitigation Measure for Impact S-1.3: Injury, Death or Property Damage from Construction Fire

S-1b Minimize Risk of Fire. During all construction activities, the Applicant shall:

- **Maintain all areas clear of vegetation and other flammable materials for at least a 30-foot radius of any welding or grinding operations, or the use of an open flame (dry vegetation shall be removed from at least a 50-foot radius of any welding or grinding operations).**
- **Spray nearby vegetation with water, using a water truck or other suitable equipment, prior to any welding or grinding operations or the use of an open flame.**
- **All equipment, gasoline-powered hand tools, and vehicles shall be equipped with spark arresters.**
- **Equip all vehicles entering the right-of-way, welding trucks or rigs with minimal fire suppression equipment (e.g., ax, bucket, 5 pound fire extinguisher, shovels, etc.).**
- **Park vehicles equipped with catalytic converters only in cleared areas.**
- **Maintain at least one half-full water truck or water tanker at each rural work site during all periods of work and for one-hour after all work has ceased for the day.**
- **Require the contractor to use dedicated fire watch during all hot work within existing operational stations (e.g., Concord or Sacramento Station).**

Residual Impact: With implementation of Mitigation Measure S-1b, Impact S.1-3 would be reduced to less than significant levels (Class II).

D.2.3.4 SFPP's Proposed System Operation

System Operation

The Proposed Project, as part of SFPP's pipeline system, would be operated from SFPP's Concord Station and monitored from the central control facility at the City of Orange Headquarters. The Sacramento Station is operated from the City of Orange Headquarters central control facility. A staff of approximately 25 people is currently employed at the Concord Station. These individuals would operate the line and conduct routine inspection and maintenance. They would also respond to possible system upset and/or failure emergencies on this portion of SFPP's pipeline system. Employees at the central facility are responsible for system monitoring and/or operation 24 hours a day.

SCADA System Control, Operation, and Safety Features

The computerized system of pipeline communications and system control is referred to as the Supervisory Control and Data Acquisition (SCADA) system. The function of SCADA is to send instructions to and receive data from Programmable Logic Controllers (PLCs) located at each facility and along the pipeline.

SFPP's SCADA system gathers and analyzes data from many sources throughout the pipeline system. The pumps are equipped with various safety devices. These include: pressure transmitters, electrical current monitors, and temperature transmitters. These devices assure reliable and safe operation of the shipping pumps.

The pipeline is protected from over-pressure by pressure control valves, pressure transmitters, and pressure relief valves. The SCADA system automatically adjusts the pressure and flow rate of the pipeline.

Pipeline operations are continuously monitored by the SCADA system. System alarms are programmed to alert operators in the event of unusual pipeline conditions (e.g., high or low pressure, low flow, etc.). The system includes automatic high-pressure shutdown of shipping pumps at the Concord pump station. Operators at Concord Station and the Controller at the City of Orange Headquarters can shutdown the pipeline. All alarms are recorded and logged at the control centers.

The SCADA system is equipped with an electrical backup system. In the event of power loss, a diesel generator can be used to run the central control center in City of Orange. Local backup power is furnished by Uninterruptible Power Supplies (UPS) at each of the critical stations and terminals.

Table D.2-26. Anticipated Performance of the LeakWarn Leak Detection System

Release Volume (Percent of Total Pipeline Flow Rate)	Time to Detect Release (minutes)
11.0	1
6.0	2
4.0	3
3.0	4
2.4	5
2.1	6
1.8	7
1.6	8
1.4	9
1.3	10
1.2	11
1.1	12

In 1999, SFPP enhanced their SCADA system. This upgrade included the installation of a system-wide satellite communications system, backup frame-relay routing capabilities, and installation of an off-site strategic backup control center. The data transmission pole times were decreased once per minute, to once every five seconds (resulting in higher data resolution and improved leak detection performance).

For this project, additional pressure and temperature transmitters would be located at the MOVs. An ultrasonic meter would also be installed at Sacramento Station to further improve the leak detection system capability.

Leak Detection System

The leak detection system would consist of 3 components: (1) volumetric balance, (2) flow difference monitoring, and (3) pressure/flow monitoring.

- **Volumetric Balance.** The volumetric balance component of the leak detection system includes modeling for fluctuations in line pack (fluid compressibility), as well as the basic volumetric balance calculations (input and output volume comparison).
- **Flow Difference Monitoring.** This leak detection component monitors for unexpected differences in pipeline flow. For example, in the event of line rupture, the flow rate at the shipping station would increase above the anticipated flow rate for a given pressure, due to the reduction in downstream friction losses.
- **Pressure/Flow Monitoring.** The pressure/flow monitoring component checks for rapid changes in the pressure and/or flow rate. Pressure and flow variation limits are configured for use in comparing the data with the expected values.

As noted earlier, the proposed pipeline would be monitored and controlled by the operators at Concord Station. The LeakWarn leak detection system would reside on a dedicated processor (with dedicated screen) at Concord Station. It would poll the field data collection locations directly (not through a SCADA server or polling hub). Thus, the SCADA system and LeakWarn would be independent of each other. The LeakWarn polling cycle (request and response time combined) to all field locations would be an estimated 5 seconds. LeakWarn's refresh cycle (processing and output time combined) to the operator's screen would be much less than one second. The total time from field data collection to output to the operator at Concord Station would be five seconds. The expected performance of the LeakWarn leak detection system is given in Table D.2-26.

SFPP's core leak detection program for the proposed 20-inch line would rely on monitoring and analysis of SCADA data, the LeakWarn leak detection software, and monitoring and analysis of system imbalances (overs and shorts). Leak detection would be accomplished by other methods. These methods would include: aerial/ground pipeline patrols; third party reports; internal pipeline inspections (smart pigs); external inspection of above grade pipe; and static pressure monitoring.

Monitoring of static pipeline pressure when the line is shut down would be used to detect unintentional releases that are too small to be detected by other methods. When a pipeline is shut down, the valves can be closed while the line is still pressured. Operators can then monitor the resulting shut-in pressure. Should an unanticipated pressure loss be observed, an unanticipated release would be suspected.

Internal pipeline inspections (smart pigs) are another method of detecting leaks that may be too small to be detected by other methods. These tools are used to evaluate the integrity of the pipe wall and the geometric shape of the pipe (dents, etc). The information from the pig runs is used to define areas of external corrosion or other pipe wall damage. SFPP has indicated that they will perform a "baseline" internal inspection for the entire pipeline after the completion of construction. Once in operation, SFPP has indicated that additional smart pig runs will be performed on the entire pipeline route every five years.

The pipeline route would be visually inspected at least bi-weekly in accordance with DOT requirements (49 CFR Part 195). The intent of these patrols is to identify third-party construction or other factors that might threaten the integrity of the pipeline. These patrols can also be used to identify small unintentional releases, which may not otherwise be detected (e.g., discoloration of vegetation, sheen on waterway, etc.)

Emergency Response

An Oil Spill Response Plan (OSRP) has been prepared for the proposed pipeline in compliance with applicable regulations. The OSRP lists emergency service providers. An Emergency Response Plan will also be prepared. These documents identify the responsible parties for the incident command and the supporting organizations/agencies.

The SFPP Concord and Sacramento Stations have fire fighting and other emergency equipment. Fire fighting equipment includes carbon dioxide and/or halon fire extinguishers inside the control rooms for electrical fires around panels and switchgear. Dry powder fire extinguishers are located in the station yard for hydrocarbon fires. Fire suppressant foaming agents (ATC concentrate) and related foam generation equipment is also onsite or readily available. Also, emergency call lists are posted at all stations, in case of accident, fire, or explosion.

D.2.3.5 Impacts of Unintentional Releases

Using the methodology detailed in Section D.2.1 of this document, tables including anticipated unintentional releases and their likely volume distributions are presented in Appendix 2 for each segment of the pipeline. Following are descriptions of types of pipeline accidents that could occur:

- **Pipeline Rupture (8,400 barrels per hour, BPH).** This hazard involves a severance of the pipeline that is large enough to allow the entire throughput (8,400 barrels per hour, BPH) to escape from the pipeline. Some of the most likely causes of a rupture would be complete pipe severance or very large hole caused by a large excavator hitting the pipeline, pipe severance caused by landslide, pipe severance caused by exposed pipe within stream channels, or pipe over pressure. For impact assessment purposes, it was assumed that the leak detection system would recognize this rupture in 1 minute; this is the fastest leak detection time provided by the Applicant, for leaks of approximately 11% of flow volume. It was also assumed that an additional five minutes would be required for the operator to analyze the data, initiate the response, stop the shipping pump, and close the MOVs. Using a maximum 8,400 BPH release flow rate and a total 6 minute time period yields an 840 barrel continued pumping release volume component for these ruptures.

Once the pipeline is shut down, the pipe contents would continue to be released at a gradually decreasing flow rate, until the line was drained from the ruptured pipeline segment between the valves. This drain down release volume would depend on the location of the pipeline rupture relative to the adjacent isolation valves and pipeline elevation profile. In the analyses, presented later in this section, the actual pipeline topography has been considered to estimate reasonable worst-case release scenarios at four sites. Using this data, the volumes of pipeline contents that would drain from the line after the adjacent block valves have been closed have been estimated. These volumes vary significantly, depending on release location, location of adjacent valves, proximity of the line and valves to emergency responders, and the pipeline elevation profile.

- **Moderate Pipeline Releases (100 BPH).** Moderate pipeline releases most commonly result from third-party damage and material failures. Generally, these unintentional releases result in lower total releases volumes than pipeline ruptures. Moderate pipeline releases and ruptures are analyzed separately because their recurrence intervals are different.

  In the analyses, a 100 barrel per hour (BPH) release rate has been considered for these moderate releases. The leak detection system would alarm within 11 minutes. This is the leak detection time provided by the Applicant for releases of approximately 1.2% of flow volume. An additional 10 minutes has been assumed for the operator to analyze the data, initiate the response, stop the shipping pump(s), and close the adjacent remotely actuated block valves. For a 100 BPH release flow rate, this would result in a 35 barrel continued pumping release volume component during this period.

  For these moderate pipeline releases, portions of the line pack were assumed to drain from the release site, based on actual site conditions. Once block valves have been closed, a portion of the entire volume between adjacent block valves would drain from the release site, depending on the pipeline elevation profile, the location of any intermediate manual or check valves, and the remoteness of the release location. For the proposed pipeline, most of the manual block valves are relatively far from manned stations. It was assumed that two hours would be required for someone to arrive at the manual block valve to close it after a release had been detected. In addition, it was assumed that four hours would be required for the arrival of emergency response equipment. Once emergency response equipment arrives on site, it was assumed that any further release could be contained and/or recovered. Therefore, in the case of a 100 BPH release, the drain down volume of the release would be limited to volume lost in the four hours before emergency response equipment would arrive on-site — 400 barrels.

- **Small Pipeline Releases (1 BPH).** These releases are below the level that can be detected by the proposed leak detection system during pipeline operation. These relatively small pipeline releases are typically caused by external corrosion. Using this release rate, it is possible that 8,760 barrels would be lost in a year. Although the ongoing over-short accounting system would normally identify this loss in less than a year, it is possible that problematic shortages can go unidentified and/or unresolved for extended periods of time. For the worst-case release analyses presented later in this section, it was assumed that the accounting system or other measures would identify a release of this volume once the system volume imbalance reached 4,000 barrels.

- **Product Fires.** A fire scenario could result from a pipeline release and a nearby source of ignition, such as a vehicle or construction machinery. The petroleum product fire hazards are strongly dependent on the type or blend of product (e.g., unleaded, diesel, jet fuel) being shipped through the pipeline, and the conditions at the release site. The possible impacts due to fire and/or explosion are discussed later in this section.

- **Other Hazards.** In addition to the four potential hazard scenarios discussed above, there are a number of secondary hazards related to pipeline operation that should to be considered. These include the potential impacts to the pipeline control and monitoring systems resulting from natural hazards, major fire, sabotage or vandalism, and the possibility of incurring damage to other utilities in the pipeline ROW during construction. Safety impacts associated with above-ground structure damage, pedestrian/vehicle collisions, and injuries to workers are other hazards that fall in this category. These hazards are discussed in applicable sections of this document.

Pipelines in Remote Areas

The remote location of a pipeline could be a pipeline risk factor due to relatively more difficult access for detection and emergency response. However, remoteness could result in less third party disruptions. Unfortunately, data is not available to allow the remoteness of a location to be evaluated with any precision. In the California study, this parameter was evaluated by differentiating between pipelines installed within Standard Metropolitan Statistical Areas (SMSA) and those installed outside these areas. Although the unintentional release rates for the lines installed within the SMSAs was roughly three times higher than those installed outside SMSAs, the data did not facilitate a statistical analysis of the affect of pipeline location. However, the statistical analysis did indicate that other factors directly affected these rates (e.g., age of pipeline, operating temperature, etc.). The remoteness of a site was considered as follows:

- **Incident Rate.** The incident rates for pipelines located in all areas were considered the same. The analysis used an average value, which represents the anticipated release history of the proposed and existing pipelines over their 50-year project life. Different pipeline unintentional release rates were not used for segments located in remote areas, versus those located in other areas. There is not adequate data available to develop different unintentional release rates for pipelines installed in different areas. In order to use this approach, a complete pipe inventory would be required for pipe located in each of these areas; unintentional release data, corresponding to the pipe located within each of these areas would also be required. This data would also need to include the variables of pipe age and operating temperature, which have been found to directly affect unintentional release incident rates. These data are not available at the present time in sufficient detail to support a statistical analysis.
- **Third Party Damage.** Intuitively, one may conclude that pipelines in urban areas or developed corridors would be subject to increased third party damage (e.g., more frequent construction, etc.). But in these areas, the one-call systems may be more widely used; these systems generally provide good protection from third party damage. The pipelines are also generally better marked. However, in very remote areas, road grading, drainage clearing, etc. may be performed without the diligent use of the one-call system. The frequency of third party incidents was different for pipelines located within and outside SMSAs in the California study; unfortunately, the data collected in the California study did not facilitate a statistical analysis of this variable.
- **Release Volume.** The location of a release site can have a direct effect on the resulting release volume. In this document, three release rates have been evaluated — pipeline rupture, moderate release, and small release. For each release site, the amount of time required for the Applicant to access the site, considering its actual location, have been estimated. In remote areas, the response time was assumed to be considerably longer than for sites located near urban areas. For the larger release rates, this caused the anticipated release volumes for releases at remote sites to be generally much larger than they would have been if they had been located in a less remote location, since the release would continue for a longer period of time. In some cases, the entire drain down release volume could be released from these remote locations.

Impact Causes and Effects

The major causes of pipeline impacts during operation are summarized in Table D.2-27. The Applicant design measures are also shown. One major impact is identified in for pipeline operation: Impact S-2 (pipeline accident causing injury or fatality).

In addition to the above Applicant design measures, which are intended to reduce the likelihood of unintentional releases from specific causes, the Applicant has proposed that some of the proposed valves be remotely actuated. Although this will not reduce the likelihood of an unintentional release, it would reduce the consequences (release volume) in most situations.

In order to understand the potential benefits of MOVs, it may be beneficial to consider a worst-case scenario. For example, a complete severance of the pipeline at a low spot in the pipeline will be considered. Once the release has been identified and the pipeline pumps have been shut down, the fluid would release from the severance at an initial flow rate, which would depend on the actual hydrostatic head (weight of the vertical column of fluid). This initial rate could actually exceed the normal maximum pipeline pumping rate. If one assumes that it could take a few hours to close a manual block valve, including travel time, an initial drain down release volume component of several thousand barrels of fluid could result. If, however, the valve were equipped with a remotely actuated mechanism, which could be closed in minutes instead of hours, the initial drain down release volume component could be reduced significantly. The actual benefits would depend on the pipeline elevation profile, valve location, and other factors, but these benefits can be significant (see Section D.2.3.7 for specific spill scenarios).

Table D.2-27. Pipeline Operation Impacts

Cause of Impact	Impact	Applicant Design Measures
External Corrosion	Property or environmental damage, injury, or death resulting from external corrosion–caused pipeline releases.	The Applicant has proposed to install a high quality Pritec exterior coating. The Applicant also plans to conduct internal inspections (smart pigs) every five years. Compliance with 49 CFR 195 Subparts C, D, F, G. and J regulatory requirements. (See Section C.2.2.1.)
Internal Corrosion	Property or environmental damage, injury, or death resulting from internal corrosion–caused pipeline releases.	The Applicant also plans to conduct internal inspections (smart pigs) every five years. Compliance with 49 CFR 195 Subparts C, D, F and G regulatory requirements. (See Section C.2.2.1.)
Third Party Damage	Property or environmental damage, injury, or death resulting from third party damage–caused pipeline releases.	The Applicant has proposed heavier wall (0.500”) pipe beneath major river crossings. Compliance with 49 CFR 195 Subparts C, D, F, and G regulatory requirements. (See Section C.2.2.1.)
Human Operating Error	Property or environmental damage, injury, or death resulting from human operating error–caused pipeline releases.	Compliance with 49 CFR 195 Subparts C, F, and G regulatory requirements. (See Section C.2.2.1.)
Design Flaw	Property or environmental damage, injury, or death resulting from design flaw–caused pipeline releases.	Compliance with 49 CFR 195 Subparts C and E regulatory requirements. (See Section C.2.2.1.)
Equipment Malfunction	Property or environmental damage, injury, or death resulting from equipment malfunction–caused pipeline releases.	Emergency backup control center
Fire	Property or environmental damage, injury, or death resulting from fire as a result of a pipeline releases.	Implementation of a leak detection system to identify potential unintentional releases.
Maintenance	Property or environmental damage, injury, or death resulting from maintenance–caused pipeline releases.	Compliance with 49 CFR 195 Subparts F and G regulatory requirements. (See Section C.2.2.1.)
Weld Failure	Property or environmental damage, injury, or death resulting from weld failure–caused pipeline releases.	Compliance with 49 CFR 195 Subpart D regulatory requirements. (See Section C.2.2.1.)

Impact S-2: Operational Pipeline Accident Causing Injuries or Fatalities

A pipeline accident could result in injuries or fatalities to nearby public (Significant, Class I)

Several separate operational impacts are described below; each is identified as a component of Impact S-2 (i.e., as Impact S-2.1, S-2.2, etc.). In the following paragraphs, the various causes of pipeline operational impacts (unintentional releases) are discussed in more detail. Mitigation measures are proposed which would reduce the likelihood and/or severity of the impact.

Impact Discussion

As presented in Section D.2.1 and summarized in Table D.2-11, most unintentional releases from hazardous liquid pipelines are relatively small and do not cause personal injuries or death. However, they can cause a wide range of impacts to natural resources. As noted earlier, the environmental impacts are covered in other issue areas (e.g., biology, water quality, etc.). In this section, impacts are evaluated only in terms of their risk to human life and safety. For example, as indicated in Table D.2-11, the following frequencies of impacts to human life are expected during the 50-year operation of the Proposed Project:

- 2.4 injuries during the project life, regardless of severity, and
- A one in two likelihood of injuries requiring hospitalization, causing loss of consciousness, or preventing the discharge of normal duties the day following the incident, and
- A one in seven likelihood that fatalities will occur during the project life.

Fire or Explosion. A fire could result from a pipeline release and a nearby source of ignition (a vehicle or construction machinery). The risk of a petroleum product fire is significant, because components of refined products such as gasoline evaporate quickly, and can form flammable vapor clouds. In the event that a pipeline accident results in a rupture or large release, there is a likelihood that the product could ignite if the following two conditions exist: (1) a high concentration of flammable hydrocarbons, and (2) a source of ignition.

A fire and explosion could cause injury or death to people close to the site, and would likely result in property damage. It is difficult to estimate the potential extent of human injury because there are so many factors affecting the size of a fire or explosion: rate of evaporation, size of the pool of products (controlled by weather including temperature), concentration of vapors (varying with wind and topographic conditions), etc.

In order for a fire or explosion to occur, there would first have to be a pipeline release. Because a small release does not generally result in a pool of products, it is not likely that a release would cause a fire or explosion. However, a pipeline rupture could result in a creation of a large enough pool of product that a fire or explosion could result.

The size of potential hazard zones (1,000 feet or more) around petroleum product release sites could result in death or injuries to up to 10 people. While this is a very unlikely event, the 1999 Bellingham accident, in which three people were killed, shows that these unlikely events do occur.

Impact Conclusion. Based on the criteria defined in Section D.2.3.2, these risks to human life are classified as significant (Class I), and **a Statement of Overriding Considerations would be required for project approval**. There is a roughly one in seven likelihood of a fatality being caused by the Proposed Project during the project life. In the following paragraphs, mitigation measures are proposed to reduce the likelihood and/or severity of the impacts to human life and safety. However, even with implementation of these measures, the impact remains significant.

General Mitigation Measures for Impact S-2, Operational Pipeline Accident Causing Injuries or Fatalities

Four general mitigation measures (S-2a through S-2d) are recommended to reduce the likelihood of an accident, and also to reduce the severity of a potential accident. Note that three additional mitigation measures are recommended for Impact S-2 in the following sections to reduce impacts from specific causes of pipeline accidents.

S-2a Supplemental Spill Response Plan. SFPP shall develop a Supplemental Spill Response Plan (SSRP) as a separate document to supplement its existing and approved Oil Spill Core Plan (OSCP) and California Marine Waters Appendices. The SSRP shall be provided to the CSLC, the California State Fire Marshal, and all jurisdictions along the pipeline ROW for review and comment prior to its finalization, and it must be approved prior to the start of pipeline operation. The SSRP shall include the following lists or information:

- **A listing of areas of archaeological sensitivity (if any) within the potentially affected spill area, incorporating any discoveries made during construction. If such areas are identified, a qualified archaeologist approved by CPUC shall monitor all cleanup activities**

that involve excavation or grading. If the archaeologist identifies resources that cannot be avoided, the specific measures described in Mitigation Measures C-1, C-2 and C-3 shall be implemented after containment of the spill is completed.

- **A listing of sensitive land uses within 500 feet of the pipeline route, including schools, residences, religious facilities, recreational lands, other land uses with large concentrations of people, and environmentally sensitive habitat areas.**

The SSRP shall also present two Response Strategies (similar to the existing response strategies included in SFPP's Oil Spill Core Plan) to address potential accidents in the Concord to Sacramento environment:

- **Pipeline Failure in an Urban Environment (applicable in the Cities of Suisun City, Fairfield, and West Sacramento), specifically describing response strategies requiring traffic control/diversion, prevention of product flow into storm drains, recovery of spilled product from storm drains or river systems, crowd control, and protection of users of nearby sensitive land uses (schools, hospitals, etc.). The strategy for responding to an urban spill shall specifically address and define appropriate response to fire and/or explosion. Where aspects of emergency response are handled or directed by local Fire Departments or other agencies, those agencies shall be contacted for input into the SSRP.**

- **Spill Reaching the Delta or Carquinez Strait, specifically identifying sensitive habitats with priority for protection, sensitive species and their potential locations in the affected Delta, marine and coastal environment. The response strategy shall list sensitive species potentially occurring in the waterway or in the Strait, and describe methods of protecting those species in the event of the worst-case spill event. It shall define specific cleanup methodology and techniques for containment and cleanup in the harbor and on the shoreline.**

  SFPP or its spill response contractor shall store equipment within one-half mile of the pipeline route between MP 9 and MP 15 to allow fast response to a spill that could affect the slough/marsh areas east of the route. Prior to pipeline operation, SFPP shall submit to the CSLC for review and approval the location of the equipment and the proposed list of spill response equipment.

S-2b Monthly Leak Detection Tests. The Applicant shall perform shut-in leak detection tests monthly. These "stand-up" tests shall be held for a period sufficient to detect a 5 BPH release, but in no case for less than 12 hours. This will reduce the potential release volumes of slow releases by a factor of twelve.

S-2c Valve Location Review. At least 60 days prior to beginning construction, SFPP shall provide to the CSLC for review and approval documentation on all pipeline valves, including those added as a result mitigation measures in the EIR. The review shall include the following:

- **A detailed pipeline profile that clearly illustrates topography along the final route.**
- **A specific review of the location of the proposed check valve at MP 20.1. An analysis shall be conducted to determine if the check valve would be more effective if it were relocated upstream of the hill which rises to an elevation of about 80 feet.**

S-2d Prevent Third-Party Damage. Between Mileposts 24.5 and 28.3 (Fairfield/Suisun City) and Mileposts 68.5 and 69.0, SFPP shall implement measures defined in API 1160 for prevention of third-party damage. SFPP shall evaluate these measures presented in API 1160 and propose specific design features for recommended implementation in these areas.

This information shall be presented to the CSLC for review and approval at least 60 days before the start of construction.

Residual Impact. While these measures could reduce both the likelihood and severity of a potential impact, a small risk remains that an accident could cause injuries or fatalities. This is considered to be a significant (Class I) impact, and **a Statement of Overriding Considerations would be required for project approval.**

The causes of these impacts to human life and safety are identified individually, in the following discussions of the Proposed Project. They are also applicable to the identified pipeline alternatives.

Impact S-2.1: External Corrosion

External corrosion can result in pipeline leaks or ruptures. (Class I)

Impact Discussion

External corrosion of a buried pipe is an electro-chemical reaction, which can occur when bare (uncoated) steel is in contact with the earth. The moist soil surrounding a pipeline can serve as an electrolyte. When this occurs, the pipe can become an anode. The current then flows through the electrolyte, from the anode (pipe) to the cathode (soil). In this instance, the anode (pipe) loses material (corrodes) as this process occurs.

The intent of an effective external corrosion prevention program is twofold. First, the pipe must be protected from corrosion by insulating it from contact with the electrolyte using an external coating. Second, in the event that the coating should fail, the pipe is prevented from becoming the anode by introducing some other material into the electrochemical chain that is more anodic than the pipe, or appears to be because of an impressed current. An impressed current or sacrificial anode cathodic protection system makes the current flow through the soil, toward the pipe, instead of away from it.

An impressed current system takes electrical power from the utility. A transformer is used to reduce the voltage. The rectifier then converts the power to a direct current. The direct current flows to and through the graphite anodes and into the surrounding earth. At locations where there may be a break in the external pipe coating (holiday), the current will reach the pipeline. It will then flow along the line to the rectifier, completing the circuit, preventing external corrosion at the external pipe coating holiday.

External corrosion typically causes a relatively large percentage of unintentional releases. Often, these leaks are relatively small in volume, with low release rates. However, they can go unnoticed for long periods of time. As a result, in some cases, the release volumes can be larger than one might expect.

To mitigate the likelihood of releases caused by external corrosion, the Applicant has proposed to install a high quality exterior pipe coating. The coating would be a Pritec 10/40 or similar polyethylene product. Finally, in the event a hole (holiday) occurs in the coating, the pipeline will be protected using an impressed current cathodic protection system.

In addition, internal inspections by "smart pigs" would be used to detect external corrosion. These inspection tools would be "launched" from a "pig launcher," located at convenient points along the pipeline and retrieved at receiving points called "pig receivers". Foam or brush pigs can also be used to clean the pipeline. Scraper pigs can be used to remove paraffin, water, and solids that might accumulate in the line during normal operations; these pigs use cups or brushes to scrape the inside of the pipe and deliver paraffin, water, and solids to the pig receivers. Internal inspection tools (smart pigs) are devices used to inspect and record the condition of the pipe. The "smart pigs" are propelled with the pipeline contents, through the line. Smart pigs detect where corrosion or other damage has affected the wall thickness or shape. There are three primary types of smart pigs available for inspection: magnetic flux, ultrasonic and caliper.

Magnetic flux (MF) pigs are the type most frequently used. As the pig travels, it magnetizes the pipe. If the pipe section is free of defects, then all of the magnetic lines of flux will be contained within the pipe wall. If there is a defect, the lines of flux will be distributed around the defect. A magnetic sensor, scanning along the inner pipe wall, detects changes in these lines of flux and outputs a corresponding electrical signal. This signal is then used to measure the defect size and shape. (Tuboscope, 1989). First generation MF pigs would generate an analog signal that needed a technician to interpret the results. A major disadvantage with these pigs was that many non-corrosion defects would be identified (due to lamination, metallurgical inclusions, dents and internal weld beads). Also, the thresholds of detection for these pigs were around 50% of wall thickness loss, and the pipeline would have to be dug to visually determine whether corrosion existed. A ”second generation” of MF smart pigs (with detection limits of about 25% to 30% of wall thickness loss) is now available; its sensors and magnets are capable of better performance than earlier designs. They have the ability to “map out” the flaws in terms of length, width and contours of wall thickness loss. This is a great advantage because it eliminates many of the false corrosion readings previously experienced.

The ultrasonic pig is a relatively new kind of smart pig that measures wall thickness by sound waves transmitted through the pipe wall. A large number of transducers are arranged in a spiral, sending pulses in sequence as the pig travels down the pipeline. The returned echoes are processed in an on-board computer for interpretation of the data. This type of pig is also capable of mapping corrosion areas, and it has the potential to detect corrosion early on (around 10% of wall thickness loss). One advantage of the ultrasound pig over the MF pig is the ability to show welding cracks, though this is much less of a problem with newly constructed pipelines. One disadvantage with the ultrasound technology is that it is new and there are still some operational problems to be ironed out. In summary, “state-of-the-art” pigs today would include both the second generation magnetic flux and ultrasound pigs.

The caliper pig is used for a different purpose than the MF and ultrasound pigs. This type of pig measures dimensional abnormalities such as dents, buckling and “out-of-roundness,” features that a corrosion pig would not detect.

SFPP will perform a baseline internal inspection (smart pig) run after pipeline construction is complete. They plan to perform subsequent smart pig runs once every five years.

Internal inspections, made with modern instrumented pigs, provide an excellent means for minimizing the likelihood of external corrosion–caused unintentional releases. This inspection method can also discover third party line damage and other line pipe defects. Further, the use of advanced coatings will minimize the likelihood of external corrosion–caused releases. As a result, Mitigation Measure S-2e is recommended.

In addition to the “smart pig” inspections, the Applicant plans to employ the following measures to minimize the recurrence of external corrosion–caused releases.

- **Rectifier Readings.** As required by 49 CFR 195.416 (c), “Each operator shall, at intervals not exceeding two-and-one-half months, but at least six times each calendar year, inspect each of its cathodic protection rectifiers.”
- **Pipe to Soil Readings.** At least once each calendar year, at intervals not exceeding 15 months, hazardous liquid pipeline operators are required to test their cathodic protection system by taking pipe to soil readings in accordance with 49 CFR 195.416 (a).
- **Corroded Pipe.** The strength of any pipe known to be corroded would normally be evaluated using ASME B31G, *Manual for Determining the Remaining Strength of Corroded Pipelines*. This method considers the size, shape, and remaining wall thickness of corroded pipe to determine its safe operating pressure.

- **Inspections.** Each time buried pipe is exposed for any reason, it would be examined for evidence of external corrosion in accordance with 49 CFR 195.416 (e). If active corrosion is found, the operator is required to investigate and determine the extent.
- **Maintain Records**. Pipeline operators are required to maintain records of the DOT required inspections.

The Applicant has proposed protecting the pipeline from external corrosion using an impressed current system. However, interference from other substructures, local soil conditions, and other factors can render an impressed current system inadequate in localized areas.

A close interval cathodic protection survey, conducted with both on-off rectifier readings, can often identify locations with cathodic protection levels below acceptable levels; these surveys can also be used to identify stray currents, which can affect cathodic protection system performance. (These surveys involve taking pipe to soil readings approximately every three feet along the entire pipeline.) Mitigation Measure S-2f it recommended to ensure that adequate cathodic protection levels are maintained throughout the operating life of the pipeline.

Mitigation Measures for Impact S-2.1: External Corrosion

S-2e **Conduct Pipeline Inspections. The Applicant shall conduct an internal pipeline inspection, using a modern instrumented internal inspection device (smart pig) and a caliper tool as soon as practical immediately after construction has been completed but before operation. Subsequent internal inspections shall be conducted within six months of the anniversary date of the first inspection, every five years. Defects shall be repaired in accordance with applicable codes, industry standards, and regulations.**

S-2f **Ensure Proper Cathodic Protection. The Applicant shall conduct a close interval survey over the entire length of the new pipeline within six months of the hydrostatic test performed prior to operation. The surveys shall be conducted in accordance with NACE standards, using both on and off rectifier readings. If inadequate cathodic protection level or cathodic protection interference is identified, these situations shall be corrected. The Applicant shall submit a report, documenting the results of the close interval inspections and any intended action to CSLC (and any other agency with permit jurisdiction), within six months after completing the close interval survey. Additional test stations shall be installed within any section found below NACE recommended levels or in areas with cathodic protection system interference; the location and spacing of these test stations shall be reported to CSLC (and any other agency with permit jurisdiction). Subsequent close interval surveys shall be conducted within six months of the DOT required annual cathodic protection survey, on sections of pipeline that show cathodic protection levels below NACE recommended levels. The Applicant shall submit a report, documenting the results of these subsequent close interval inspections and any intended corrective action to CSLC (and any other agency with permit jurisdiction), within six months after completing the close interval survey. These other agencies may include, but are not limited to, Office of the California State Fire Marshal Pipeline Safety Division, the United States Department of Transportation Office of Pipeline Safety, and any other agency with environmental permit or land ownership responsibilities. (These requirements are more restrictive than the minimum requirements included in 49 CFR 195.)**

Residual Impact. With the proposed mitigation, the likelihood of external corrosion causing a pipeline accident will be reduced, but even with inspections, external corrosion remains a frequent cause of pipeline accidents. As stated above, Impact S-2.1 remains significant (Class I), **requiring that the CSLC prepare a Statement of Overriding Considerations for project approval.**

Impact S-2.2: Internal Corrosion

Internal corrosion could cause a pipeline accident. (Potentially Significant, Class II)

Impact Discussion

Internal corrosion is another cause of unintentional pipeline releases. Although refined petroleum products are generally not considered corrosive, 49 CFR 195.418 outlines the regulatory requirements for internal corrosion control and monitoring.

Mitigation Measure for Impact S-2.2: Internal Corrosion

The smart pig inspections, recommended in Mitigation Measure S-2e, will also detect anomalies caused by internal corrosion.

Residual Impact. Mitigation Measure S-2e, coupled with compliance with the existing federal and State regulations is considered to be adequate to minimize the risk of accidents caused by internal corrosion to less than significant levels (Class II).

Impact S-2.3: Third Party Damage to Proposed Pipeline

Third party damage could cause a pipeline accident. (Significant, Class I)

Impact Discussion

Like external corrosion, third party damage causes a large percentage of unintentional pipeline releases. Geological and hydrological hazards (e.g., landslide, exposed pipe within stream channel) can also cause third party/outside force pipeline incidents. These impacts are addressed in the Geology and Hydrology sections (D.7 and D.8).

As noted above, there are several mechanisms for reducing the frequency of third party damage–caused releases. Some of these include:

- **One Call System.** Participation in a one-call system meets the requirements for an operator's damage prevention program, per 49 CFR 195.442 and California State law
- **Line Marking.** 49 CFR 195 prescribes the minimum line marking requirements.
- **Right-of-Way Inspection.** 49 CFR 195.412 requires, "Each operator shall, at intervals not exceeding three weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way." Methods of inspection include walking, driving, flying, or other appropriate means of traversing the right-of-way.
- **Public Education.** 49 CFR 195.440 requires pipeline operators to, ". . . establish a continuing educational program to enable the public, appropriate government organizations and persons engaged in excavation-related activities to recognize a hazardous liquid or a carbon dioxide pipeline emergency and to report it to the operator or the fire, police, or other appropriate officials . . . ."==
- **Facility Security.** 49 CFR 195.436 requires, "Each operator shall provide protection for each pumping station and breakout tank area and other exposed facility (such as scraper traps) from vandalism and unauthorized entry."

Clear line markings can help prevent third party intrusions. As a result, Mitigation Measure S-2g is recommended to require adequate pipeline marking. This will minimize the frequency of impacts that may result from third party damage–caused releases.

Mitigation Measure for Impact S-2.3: Third Party Damage

S-2g Pipeline Markers. The Applicant shall install and maintain durable line markers in sufficient quantity and at such locations to ensure continuous line-of-site marking along the pipeline (two line markers visible from any one location); however, markers shall in no case be installed more than 1,000 feet apart. Markers shall also be installed and maintained on each side of all paved and unpaved road crossings, on each side of all railroad crossings, and on each side of all waterways.

For new pipeline construction, a minimum 3" wide, 6 mil, polyethylene marking tape shall be installed 12-inch to 18" beneath the finished ground surface, at each edge of the pipe ditch, within 12 to 18" of the pipe centerline. An appropriate warning shall be printed on the tape (e.g., "Warning – Hazardous Liquid Pipeline"). As an alternative, the Applicant may propose to the CSLC to install an optical or electronic intrusion detection system, increase the depth of cover, or increased wall thickness to mitigate the potential for third party incidents, as described in Section 10 of API Standard 1160, *Managing System Integrity for Hazardous Liquid Pipelines*.

Residual Impact. Even with implementation of Mitigation Measure S-2g, the likelihood of occurrence of Impact S-2.3, third party damage to cause pipeline accidents remains high so the impact remains significant.

Impact S-2.4: Operator Error

Pipeline operator error can result in pipeline accidents or reduced response capability. (Less than Significant, Class III)

Impact Discussion

49 CFR 195 provides specific requirements for pipeline operations and maintenance manuals and procedures. However, in a 1999 pipeline release and fire on the Olympic pipeline in Bellingham, Washington, which resulted in three fatalities, early reports indicate that operator error and SCADA System malfunction contributed to the severity of the incident. As a result of this incident, the federal regulations for operator training were recently enhanced. In light of the anticipated low frequency of operator error–caused unintentional pipeline releases, the proposed leak detection system, the historic low incident rate of these incidents on other pipelines, and the recent enhancement of the federal regulations, additional mitigation measures beyond those required by DOT and those already proposed by the Applicant are not recommended.

Mitigation Measures: None recommended.

Residual Impact: Less than significant.

Impact S-2.5: Design Flaw (Engineering)

Design flaws or incomplete/inadequate engineering can contribute to likelihood of a pipeline accident. (Less Than Significant, Class III)

Impact Discussion

Design or engineering flaws are not noted as causing a large percentage of the unintentional pipeline releases. However, this does not necessarily mean that proper engineering design is not a factor in minimizing the likelihood and severity of an unintentional release. To the contrary, a quality engineering effort will reduce the likelihood and severity of releases caused by a number of factors. For example, the engineering effort can reduce the likelihood of external corrosion–caused releases by enhancing the design of the cathodic protection and coating system. The frequency of third party damage–caused releases can be reduced by employing certain engineering techniques. The likelihood of over-stressed pipeline conditions can be virtually eliminated (e.g., pipe can be installed in a manner which protects it from geological and other hazards).

A third party engineering review, or an independent third party construction inspection, is not required by 49 CFR 195 or any other applicable regulation. Although 49 CFR 195 does require that "each pipeline system must be constructed in accordance with comprehensive written specifications or standards that are consistent with the requirements of this part." Third party design reviews and inspections are employed in many other industries to help protect public safety, public health, the environment, property, and/or the public welfare. For example, the widely adopted Uniform Building Code gives local building officials the responsibility for independent design reviews (plan checks) and construction observations of buildings and structures prior to occupancy. To minimize the risks associated with pipeline operation, the CSLC should implement the design review defined below, prior to pipeline operation.

Pipeline Design Review. Prior to final approval of the construction drawings, the CSLC will conduct an independent third party design review of the Applicant-proposed construction drawings and specifications. The intent of this review and observation would be to help ensure adherence with the project mitigation measures, the project construction drawings and specifications, and the minimum regulatory requirements. Further, this effort would help ensure that the Applicant-proposed design measures are actually constructed, project specific needs are met, and the adopted mitigation measures are incorporated into the design and pipeline construction. In addition, compliance with the applicable codes, standards, regulations, industry practices, etc. would be verified. The design review and construction observation services would not in any way be intended to relieve the Applicant of its responsibility and liability for the design, construction, operation, maintenance or emergency response of these facilities.

Mitigation Measure for Impact S-2.5: Design Flaw

Assuming CSLC implementation of design review defined above, no additional mitigation is required.

Residual Impact: Less than significant (Class III).

Impact S-2.6: Equipment Malfunction

Malfunction of equipment can cause small pipeline releases. (Less Than Significant, Class III)

Impact Discussion

Equipment malfunction incidents typically cause relatively small releases. However, they occasionally result in a larger release volume or personal injury (primarily to pipeline operator personnel). No additional mitigation measures are proposed.

Mitigation Measures: None required.

Residual Impact: Less than significant (Class III).

D.2.3.6 Frequency of Accidents from Proposed Project

Using the data presented in Section D.2.1, the frequency of unintentional releases from the proposed pipeline, for all releases, regardless of release volume, is expected to be 2.88 incidents per 1,000 mile-years. For the proposed new 70-mile, 20-inch-diameter pipeline, the results are summarized in Table D.2-28. The pipeline spill information is presented for use by authors of other disciplines analyzed in this EIR so they can determine impact significance of a pipeline accident in their areas of study.

It is often desirable to analyze the anticipated frequency of unintentional releases at a specific location along a pipeline. The anticipated frequency of releases per year and the recurrence intervals have been provided in Table D.2-29 for releases from any newly constructed one-mile segment of 20-inch-diameter pipeline.

Probable Unintentional Release Volume Distribution

Occasionally, incident rate data such as those presented in the prior tables are mistakenly assumed to represent the likelihood of a worst-case release. However, these figures represent the probable likelihood of any release, regardless of release volume. In fact, most releases are relatively small.

Four different release volumes have been identified — small, medium, large, and very large. Although somewhat arbitrary, these release volumes have been defined in Table D.2-30. The percentiles given correspond to new 20-inch-diameter pipe.

Table D.2-28. Anticipated Unintentional Releases from Proposed New 70-Mile, 20-Inch-Diameter SFPP Pipeline

Unintentional Release Cause	Unintentional Release Rate (per 1,000 mile-years)	Pipeline Section Length (miles)	Unintentional Releases per Year	Recurrence Interval (years)
External corrosion	1.00	70	0.0700	14
Internal corrosion	0.19	70	0.0133	75
3rd party damage	0.40	70	0.0280	36
Human operating error	0.11	70	0.0077	130
Design flaw	0.03	70	0.0021	476
Equipment malfunction	0.37	70	0.0259	39
Maintenance	0.07	70	0.0049	204
Weld failure	0.26	70	0.0182	55
Other	0.45	70	0.0315	32
Total, all unintentional releases, regardless of volume	2.88	70	0.2016	5
DOT reportable unintentional releases (50 barrels or greater)	1.10	70	0.0770	13
Injuries, regardless of severity	0.685	70	0.0480	21
Injuries requiring hospitalization, causing loss of consciousness, or preventing discharge of normal duties the day following the incident	0.150	70	0.0105	95
Fire	Probability for fire incidents is less than the probability of the releases shown in this table because, in addition to presence of product, a fire requires the presence of an appropriate source of ignition.			
Fatalities	0.042	70	0.0029	340

Table D.2-30. Unintentional Release Volume Distribution from New 20-Inch Pipe

Unintentional Release Volume	Anticipated Release Volume, Barrels (gallons)
Small Release (5 Percentile)	≥1 (42)
Medium Release (71 Percentile)	≥100 (4,200)
Large Release (87 Percentile)	≥1,000 (42,000)
Very Large Release (98 Percentile)	≥10,000 (420,000)

Table D.2-29. Anticipated Unintentional Releases from Any One-Mile Section of the Proposed New 70-Mile, 20-Inch-Diameter SFPP Pipeline

Unintentional Release Cause	Unintentional Release Rate (per 1,000 mile-years)	Pipeline Section Length (miles)	Unintentional Releases per Year	Recurrence Interval (years)
External corrosion	1.00	1	0.0010	1,000
Internal corrosion	0.19	1	0.0002	5,263
3rd party damage	0.40	1	0.0004	2,500
Human operating error	0.11	1	0.0001	9,091
Design flaw	0.03	1	0.0000	33,333
Equipment malfunction	0.37	1	0.0004	2,703
Maintenance	0.07	1	0.0001	14,286
Weld failure	0.26	1	0.0003	3,846
Other	0.45	1	0.0005	2,222
Total, all unintentional releases, regardless of volume	2.88	1	0.0029	347
DOT reportable unintentional releases (50 barrels or greater)	1.10	1	0.0011	907
Injuries, regardless of severity	0.685	1	0.0007	1,460
Injuries requiring hospitalization, causing loss of consciousness, or preventing discharge of normal duties the day following the incident	0.150	1	0.0002	6,667
Fire	Probability for fire incidents is less than the probability of the releases shown in this table because, in addition to presence of product, a fire requires the presence of an appropriate source of ignition.			
Fatalities	0.042	1	0.0000	23,810

The determination of worst-case release volumes is generally site-specific; worst-case release volumes will be developed later in this document for four sites, using project and site-specific data. In Table D.2-31, the anticipated release volume distribution is presented for the proposed new 70-mile, 20-inch-diameter pipeline. This table also includes the recurrence interval for releases of various volumes from any one-mile pipe segment. (The methodology for these calculations was presented earlier in Section D.2.1.) In Appendix 2, similar data is presented for each of the seven pipe segments.

Table D.2-31. Anticipated Unintentional Release Volume Distribution from Proposed New 70-Mile, 20-Inch-Diameter SFPP Pipeline

Unintentional Release Volume, Barrels (gallons)	Anticipated Unintentional Releases Per Year – Entire 70-Mile Section	Anticipated Recurrence Interval (Years) – Entire 70-Mile Section	Anticipated Unintentional Releases Per Year – Any One-Mile Section	Anticipated Recurrence Interval (Years) – Any One-Mile Section	Anticipated Unintentional Releases Over 50-Year Project Life
All Unintentional Releases (regardless of volume)	0.2016	5	0.00288	347	10.08
Small Unintentional Release ≥1 (42)	0.1925	5	0.00275	363	9.63
≥5 (210)	0.1470	7	0.00210	476	7.35
≥10 (420)	0.1225	8	0.00175	572	6.12
≥50 (2,100)	0.0770	13	0.00110	907	3.86
Medium Unintentional Release ≥100 (4,200)	0.0584	17	0.000834	1,199	2.92
≥500 (21,000)	0.0341	29	0.000487	2,053	1.71
Large Unintentional Release ≥1,000 (42,000)	0.0269	37	0.000384	2,607	1.34
≥5,000 (210,000)	0.0095	106	0.000135	7,413	0.47
Very Large Unintentional Release ≥10,000 (420,000)	0.0048	207	0.000069	14,594	0.24

D.2.3.7 Spill Scenarios

Four locations were selected for a site-specific analysis of a potential unintentional release. For these sites, four primary hazard scenarios associated with the operation of refined petroleum product pipelines have been considered. These scenarios are: (1) unintentional releases from pipeline ruptures, (2) unintentional releases from moderate pipeline leaks, (3) unintentional releases from small pipeline leaks, and (4) refined petroleum product fires or explosions. The four sites are:

- MP 5.06, near the Carquinez Strait crossing.
- MP 19.4, near the Cordelia Creek crossing.
- MP 27.7, near apartment buildings.
- MP 65.2, in West Sacramento, near the Sacramento River.

The analysis of a worst-case release at each of these sites was based on the ability of the Applicant's proposed leak detection system to identify an unintentional release, the anticipated response time of an operator, the location of remotely operated block valves, the location of manually operated block valves, the terrain, the time required to reach the manual block valves to close them, and the anticipated time required for initial emergency response equipment (e.g., vacuum trucks) to access the site. (The methodology, including the response times and other assumptions for these analyses were presented earlier, in Section 2.3.5.)

Scenario #1: Analysis of Impacts of an Unintentional Release at the Carquinez Strait Crossing (MP 5.06)

The following paragraphs explore the anticipated results of three unintentional release scenarios from a release at MP 5.06: a complete pipeline severance, a 100 barrel per hour (BPH) release, and a 1 BPH release. It was assumed that the location of the release would be at the south shore of the Carquinez Strait, at MP 5.06. There are remotely operated block valves at each side of this crossing, at MP 4.747

and MP 6.246. The elevation of the section between the valves is mostly below the level of the potential release location, due to the underwater crossing. Once the block valves are closed, the maximum drain down volume would be the volume between the valve on the south shore and the location of the release. This volume was calculated, for the existing 14-inch-diameter pipe, to be 279 barrels. In both the 8,400 BPH and the 100 BPH release scenarios, this entire pipe volume would be released before the arrival of emergency response equipment. Table D.2-32 depicts the anticipated results.

The terrain generally slopes downward, and the valves are located very close to the crossing. Additional valves would not appreciably decrease the release volume on this segment. However, Mitigation Measure S-2b (above) is recommended to reduce the impacts associated with slow releases (1 BPH) in this sensitive area by requiring monthly leak detection tests. This would reduce the volume that could be released from a potential worst-case of 8,760 barrels (or a reasonable worst-case of 4,000 barrels) to 730 barrels. The impact of a pipeline accident is still considered to be significant (Class I).

Scenario #2: Analysis of Impacts of an Unintentional Release Northeast of Cordelia Creek

The second release site to be analyzed was located near the proposed Cordelia Creek crossing, at MP 19.4. This potential release site is located in a valley, between two hills (50 feet and 80 feet).

Remotely operated block valves are proposed to be located at MP 6.246 and MP 24.75. One manual block valve is located between the two MOVs at MP 15.15. Since the manual block valve is in a rural location, it was assumed that it would take 2 hours to access and close this valve. It was assumed that it would take an additional two hours (four hours total from leak detection) for emergency response equipment to arrive on site. There is also one check valve at MP 20.1.

The elevation data provided indicates that the check valve is located on the downstream side of the 80-foot hill. Mitigation Measure S-2c proposes a general review of proposed valves and the specific relocation of a check valve to a point upstream of the 80-foot hill, where it would be more useful. This mitigation measure would also reduce the maximum potential release volume at this location by 10%.

Table D.2-32. Unintentional Release Volumes – MP 5.06, Upstream of Carquinez Strait Crossing

Unintentional Release Rate	8,400 BPH		100 BPH		1 BPH	
Sequence Description	Time (minutes)	Unintentional Release Volume (barrels)	Time (minutes)	Unintentional Release Volume (barrels)	Time (minutes)	Unintentional Release Volume (barrels)
Time required for release detection system to detect unintentional release	1	140	11	18	1 year	4,000 (see note 5)
Time between unintentional release detection and pump stoppage/block valve closure	5	700	10	17	N/A	0
Drain down between adjacent block valves after MOV closure, prior to emergency response arrival (see note 3)	240	279	240	279	N/A	Negligible
Total unmitigated unintentional release volume	N/A	1,119	N/A	314	N/A	4,000
Anticipated recurrence interval for unintentional releases of this volume (see note 4)	2,450 years		1,500 years		7,869 years	
Total mitigated unintentional release volume	N/A	1,119	N/A	314	1 month	730
Percentage reduction	N/A	0%	N/A	0%	N/A	81%

Notes:
1. The drain down time for the 100 BPH release rate assumes that, even after pump shut-off, there will be no decrease in release flow rate. In reality, after pump shut-off, the release flow rate may decrease.
2. The fluid decompression release volume component has not been included in the above analyses; it would tend to increase the release volumes somewhat. Any resulting error is not significant, since the range in the accuracy of the assumptions made are greater than the decompression release volume.
3. The time between the detection of the release and the arrival of the emergency response equipment was assumed to be four hours.
4. The recurrence interval is for a release of this volume, located within 1 mile of the analyzed release location.
5. Although a release volume of 8,760 barrels is theoretically possible (1 BPH x 24 hours per day x 365 days per year), once the system volume imbalance reaches 2,000 to 4,000 barrels, it will likely be identified by the Applicant's mass balance leak detection system or off-line system accounting.

Once the block valves are closed, the total potential drain down volume to the release site is 4,295 barrels. At a release flow rate of 8,400 BPH, which is reasonable considering the local hydraulics, the entire drain down volume would be lost in approximately one-half hour. Since it was assumed that closing the manual block valve would take up to two hours, the manual block valve at MP 15.15 would not be effective in reducing the release volume in the event of a pipe rupture. After the manual block valve has been closed, the potential drain down volume would be reduced to 1,863 barrels.

At a release rate of 100 BPH, it would take approximately 18 hours to release the entire drain down volume. It was assumed that emergency response equipment would arrive within 4 hours after leak detection. Even with implementation of Mitigation Measure S-2c (above), which requires a review of valve locations, the impact of a pipeline accident remains significant (Class I). The release information is summarized in Table D.2-33.

Scenario #3: Analysis of Impacts of an Unintentional Release near Apartment Buildings, at MP 27.7

The third release site analyzed was near the apartment buildings at MP 27.7. This potential release site is located in a valley, approximately one third of the way up an 110-foot elevation incline. Remotely operated block valves are located at MP 24.75 and MP 65.5. There are four manual block valves between these MOVs. The manual block valves are located on the opposite side of the 110-foot hill, so they would not be effective in reducing the volume of an unintentional release at this site.

Table D.2-33. Unintentional Release Volumes – MP 19.4, Near Cordelia Creek

Unintentional Release Rate	8,400 BPH		100 BPH		1 BPH	
Sequence Description	Time (minutes)	Unintentional Release Volume (barrels)	Time (minutes)	Unintentional Release Volume (barrels)	Time (minutes)	Unintentional Release Volume (barrels)
Time required for leak detection system to detect unintentional release	1	140	11	18	1 year	4,000 (see note 6)
Time between unintentional release detection and pump stoppage/block valve closure	5	700	10	17	N/A	0
Drain down between adjacent block valves after MOV closure, prior to manual block valve closure (see note 4)	120	4,295	120	200	N/A	Negligible
Drain down between adjacent block valves after MOV and manual block valve closure, prior to emergency response arrival	120	0	120	200	N/A	Negligible
Total unmitigated unintentional release volume	N/A	5,135	N/A	435	N/A	4,000
Anticipated recurrence interval for unintentional releases of this volume (see note 5)	7,615 years		2,042 years		5,695 years	
Total mitigated unintentional release volume	N/A	4,622	N/A	435	1 month	730
Percentage reduction	N/A	10%	N/A	0%	N/A	81%

Notes:
1. The drain down time for the 100 BPH release rate assumes that, even after pump shut-off, there will be no decrease in release flow rate. In reality, after pump shut-off, the release flow rate may decrease.
2. The drain down time for the 8,400 BPH release rate is based on a rough hydraulic analysis. The location between adjacent valves with the highest elevation was used to determine the head and the flow rate after pump shut-off.
3. The fluid decompression release volume component has not been included in the above analyses; it would tend to increase the release volumes somewhat. Any resulting error is not significant, since the range in the accuracy of the assumptions made are greater than the decompression release volume.
4. The time to close the manual block valve was assumed to be two hours after release detection. The time between the detection of the release and the arrival of the emergency response equipment was assumed to be four hours (two hours after manual block valve closure).
5. The recurrence interval is for a release of this volume, located within 1 mile of the analyzed release location.
6. Although a release volume of 8,760 barrels is theoretically possible (1 BPH x 24 hours per day x 365 days per year), once the system volume imbalance reaches 2,000 to 4,000 barrels, it will likely be identified by the Applicant's mass balance leak detection system or off-line system accounting.

Once the block valves are closed, the total potential drain down volume is 8,268 barrels. At a release flow rate of 8,400 BPH, which is reasonable with the local hydraulics, this volume would be lost in less than one hour.

At a release rate of 100 BPH, it would take approximately 83 hours to lose this entire drain down volume. It was assumed that emergency response and release control equipment would arrive within 4 hours after leak detection, so in the case of a 100 BPH release, 400 barrels (17,000 gallons) would be lost after initial block valve closure.

Given the relatively high population density at this location, even a very unlikely pipeline accident, with the potential for ignition and fire/explosion, is a major concern. This is an area in which the potential for a large spill should be minimized, even though the significant (Class I) impact will remain. In urban areas, the most frequent cause of accidents is because of third-party damage. Therefore, to reduce the likelihood of third-party damage causing a pipeline rupture in populated areas, Mitigation Measure S-2d (above) is recommended.

Table D.2-34. Unintentional Release Volumes – MP 27.7, Adjacent to Apartment Buildings

Unintentional Release Rate	—— 8,400 BPH ——		—— 100 BPH ——		—— 1 BPH ——	
Sequence Description	Time (minutes)	Unintentional Release Volume (barrels)	Time (minutes)	Unintentional Release Volume (barrels)	Time (minutes)	Unintentional Release Volume (barrels)
Time required for leak detection system to detect unintentional release	1	140	11	18	1 year	4,000 (see note 6)
Time between unintentional release detection and pump stoppage/block valve closure	5	700	10	17	N/A	0
Drain down between adjacent block valves after MOV closure, prior to emergency response arrival (see note 4)	240	8,268	240	400	N/A	Negligible
Total unmitigated unintentional release volume	N/A	9,108	N/A	435	N/A	4,000
Anticipated recurrence interval for unintentional releases of this volume (see note 5)	—— 13,825 years ——		—— 2,042 years ——		—— 5,695 years ——	
Total mitigated unintentional release volume	N/A	9,108	N/A	435	1 month	730
Percentage reduction	N/A	0%	N/A	0%	N/A	81%

Notes:
1. The drain down time for the 100 BPH release rate assumes that, even after pump shut-off, there will be no decrease in release flow rate. In reality, after pump shut-off, the release flow rate may decrease.
2. The drain down time for the 8,400 BPH release rate is based on a rough hydraulic analysis. The location between adjacent valves with the highest elevation was used to determine the head and the flow rate after pump shut-off.
3. The fluid decompression release volume component has not been included in the above analyses; it would tend to increase the release volumes somewhat. Any resulting error is not significant, since the range in the accuracy of the assumptions made are greater than the decompression release volume.
4. The time to close the manual block valve was assumed to be two hours after release detection. The time between the detection of the release and the arrival of the emergency response equipment was assumed to be four hours (two hours after manual block valve closure).
5. The recurrence interval is for a release of this volume, located within 1 mile of the analyzed release location.
6. Although a release volume of 8,760 barrels is theoretically possible (1 BPH x 24 hours per day x 365 days per year), once the system volume imbalance reaches 2,000 to 4,000 barrels, it will likely be identified by the Applicant's mass balance leak detection system or off-line system accounting.

Scenario #4: Analysis of Impacts of an Unintentional Release near the Sacramento River, MP 65.2

The fourth release site analyzed was in West Sacramento, near the Sacramento River, at MP 65.2. Remotely actuated block valves are located at MP 24.75 and MP 65.5. There are four manual block valves in between, at MP's 34.75, 44.61, 54.41, and 61.9. Since the nearest manual block valve is located very close to Sacramento, it was assumed that it would only take one hour to close the valve. It was assumed that emergency response, capable of containing the volume being released, would take four hours from leak detection (three hours after manual block valve closure).

This release site is located at the lowest point following a 100-foot elevation decrease, from a hill at MP 32.6. A significant portion of the drain down volume would come from the section of pipe between MP 57.8 and 65.2. The elevation decreases from about 25 feet to 10 feet over this 7.4-mile section. Once the MOVs have been closed, the potential drain down volume is 22,428 barrels. However, neither a complete rupture nor a 100 BPH release is anticipated to release this entire volume.

Table D.2-35. Unintentional Release Volumes – MP 65.2, Near the Sacramento River

Unintentional Release Rate	8,400 BPH		100 BPH		1 BPH	
Sequence Description	Time (minutes)	Unintentional Release Volume (barrels)	Time (minutes)	Unintentional Release Volume (barrels)	Time (minutes)	Unintentional Release Volume (barrels)
Time required for leak detection system to detect unintentional release	1	140	11	18	1 year	4,000 (see note 6)
Time between unintentional release detection and pump stoppage/block valve closure	5	700	10	17	N/A	0
Drain down between adjacent block valves after MOV closure, prior to manual block valve closure (see note 4)	60	3,311	60	100	N/A	Negligible
Drain down between adjacent block valves after MOV and manual block valve closure, prior to emergency response arrival	180	6,842 (see note 2)	180	300	N/A	Negligible
Total unmitigated unintentional release volume	N/A	10,153	N/A	435	N/A	4,000
Anticipated recurrence interval for unintentional releases of this volume (see note 5)	14,726 years		2,042 years		5,695 years	
Total mitigated unintentional release volume	N/A	10,153	N/A	435	N/A	730
Percentage reduction	N/A	0%	N/A	0%	N/A	81%

Notes:
1. The drain down time for the 100 BPH release rate assumes that, even after pump shut-off, there will be no decrease in release flow rate. In reality, after pump shut-off, the release flow rate may decrease.
2. The drain down time for the 8,400 BPH release rate is based on a rough hydraulic analysis. The location between adjacent valves with the highest elevation was used to determine the head and the flow rate after pump shut-off.
3. The fluid decompression release volume component has not been included in the above analyses; it would tend to increase the release volumes somewhat. Any resulting error is not significant, since the range in the accuracy of the assumptions made are greater than the decompression release volume.
4. The time to close the manual block valve was assumed to be one hour after release detection. The time between the detection of the release and the arrival of the emergency response equipment was assumed to be four hours (three hours after manual block valve closure).
5. The recurrence interval is for a release of this volume, located within 1 mile of the analyzed release location.
6. Although a release volume of 8,760 barrels is theoretically possible (1 BPH x 24 hours per day x 365 days per year), once the system volume imbalance reaches 2,000 to 4,000 barrels, it will likely be identified by the Applicant's mass balance leak detection system or off-line system accounting.

For a pipe rupture, a rough hydraulic analysis indicated that once the MOVs have been closed, the 8,400 BPH flow rate should slow to approximately 3,311 BPH. Once the manual block valve has been closed, the potential drain down volume drops to 6,842 barrels. A rough hydraulic analysis determined that the 8,400 BPH flow rate would be approximately 2,607 BPH after manual block valve closure. Therefore, although there is a potential for 22,428 barrels to be released, it is likely that, even in a worst-case pipeline rupture, only 10,153 barrels would be released before emergency response equipment capable of containing the release arrives on site.

D.2.3.8 Environmental Impacts of the Cordelia Mitigation Segment

This mitigation segment was developed to avoid sensitive biological and water resources within Cordelia Marsh and Slough. The 2.6-mile segment diverges from the proposed route at MP 17.6 and rejoins the proposed route at approximately MP 20.0. The Cordelia Mitigation Segment parallels Ramsey Road until

Cordelia Road, where it continues along Cordelia Road to the UPRR ROW where it rejoins the proposed route (see Figure D.4-3).

The Cordelia Mitigation Segment would be approximately 0.2 miles longer than the Proposed Route segment. The anticipated unintentional releases per mile are the same as those given in Table D.2-29; however, spill response would be slightly better on the mitigation segment because of the improved road access.

Construction and operational impacts associated with the Cordelia Mitigation Segment would be similar to those described for the Proposed Project. Because the segment ROW is primarily located within paved roadways (compared with the original route in dirt roads and unpaved, little used transmission ROW), there would be more of a potential for construction impacts associated with traffic collisions caused by poor signage, distraction by construction equipment, or a constrained roadway, traffic excursions into pipe ditch, and/or severance of third party substructures during construction. These impacts are all Class II, mitigable to less than significant levels with implementation of Mitigation Measures T-1b and S-1b.

Overall, the Cordelia Mitigation Segment is preferred over the proposed route segment.

D.2.3.9 Impacts of Proposed Station Changes

The impacts associated with the proposed station changes have been presented in Table D.2-36. These impacts are generally the same as those for the pipeline construction presented in Table D.2-25. No Applicant design measures are known at this time.

Table D.2-36. Impacts of Proposed Station Changes

Cause of Impact	Impact Designation and Effect
Fire	Personal injury or property damage resulting from construction-caused fire.
Purging, cleaning, or hydrostatic testing	Personal injury (primarily construction worker) or property damage caused by improper operations or equipment failure during line cleaning, hydrostatic testing, and line drying.
Unintentional releases from station piping	Unintentional releases can result from Station piping from a variety of causes: external corrosion, internal corrosion, 3rd party damage, operating error, design flaw, equipment malfunction, maintenance, weld failure, etc.

Many of the impacts associated with the proposed station modifications are the same as those for the buried pipeline construction and operation. As a result, the same mitigation measures presented in Section D.2.3.5 of this report may be used to minimize the likelihood and severity of these impacts. Table D.2-37 presents a matrix, showing the cause of the impact, the impact designation, the effect, and the proposed mitigation measure.

D.2.3.10 Impacts of Pipeline Abandonment

Impact S-3: Pipeline Abandonment

Improper pipeline abandonment could cause contamination, landslides, or erosion. (Less Than Significant, Class II)

Pipeline operators generally proposed to abandon pipelines in place. This normally involves displacing the pipeline contents with nitrogen. This practice of purging abandoned pipelines with nitrogen may not remove all products. This practice, in lieu of pipeline removal, also poses the potential for the abandoned pipe to become a future conduit for underground or surface waters, after it deteriorates. Further, the soil above the pipeline could settle after the pipe deteriorates.

Table D.2-37. Proposed Above Grade Construction Mitigation Measures

Cause of Impact	Impact Designation and Effect	Impact Classification	Mitigation Measure
Fire	Personal injury, death, or property damage resulting from construction-caused fire.	Class II	S-1b: The likelihood of a fire being caused by above grade construction will be reduced with implementation of this measure. As a result, this is a Class II impact, significant but mitigable to less than significant levels.
Purging, cleaning, or hydrostatic testing	Personal injury, death, or property damage caused by improper operations or equipment failure during line cleaning, hydrostatic testing, and line drying.	Class III	No additional mitigation measures are proposed to protect the public.
Unintentional releases from station piping	Unintentional releases can result from Station piping from a variety of causes: external corrosion, internal corrosion, 3rd party damage, operating error, design flaw, equipment malfunction, maintenance, weld failure, etc.	Class I	S-2e, S-2f, S-2g: The likelihood of an unintentional release from the proposed station modifications resulting from external corrosion, internal corrosion, 3rd party damage, operating error, design flaw, equipment malfunction, maintenance, weld failure, or other cause may be classified as likely, with negligible to severe impacts. With the proposed mitigation, the likelihood will be reduced, but this remains a Class I impact, significant and unavoidable.

If all of the free product is not removed, it could leak from the pipe as it deteriorates. If the pipe acts as a conduit for underground water, it could cause landslides, erosion, and other damage. If the soil settles, it can redirect surface water flows, causing localized erosion. The impacts associated with the pipeline abandonment are presented in Table D.2-38. Mitigation Measure S-3a is recommended to reduce potential impacts of pipeline abandonment.

Table D.2-38. Impacts of Pipeline Abandonment

Cause of Impact	Impact Designation and Effect
Deterioration of abandoned pipe	Deteriorated pipe may act as a conduit for underground or surface waters. It may also result in localized ground settlement that can redirect surface water drainage resulting in localized erosion, landslides, and other instability.
Inadequate cleaning	Environmental contamination can be caused by refined petroleum hydrocarbons leaking from deteriorated pipe.

Mitigation Measure for Impact S-3: Pipeline Abandonment

Table D.2-39 summarizes the impacts and relevant mitigation measures for pipeline abandonment. Recommended Mitigation Measure S-3a follows the table.

Table D.2-39. Proposed Pipeline Abandonment Mitigation Measures

Cause of Impact	Impact Designation and Effect	Impact Classification	Mitigation Measure
Deterioration of abandoned pipe	Deteriorated pipe may act as a conduit for underground or surface waters. It may also result in localized ground settlement that can redirect surface water drainage resulting in localized erosion, landslides, and other instability.	Class II	S-3a: Pipeline Abandonment Procedures (below)
Inadequate cleaning	Environmental contamination can be caused by refined petroleum hydrocarbons leaking from deteriorated pipe.	Class II	S-3a: Pipeline Abandonment Procedures (below)

S-3a Pipeline Abandonment Procedures. Once the majority of the product has been removed, a series of foam pigs shall be pushed through the abandoned pipeline to remove any residual product. This process shall be repeated until the pigs are free of residual product.

Over time, local land uses and other site environments will change. As a result, it would be impossible to prepare a plan that would adequately cover future abandonment at this time. As a result, the Applicant shall submit a site-specific letter report to the CSLC or any other agency with permit authority, at least 60 days prior to any pipeline abandonment. The report shall evaluate any potential risks that could be imposed by the deteriorated pipe acting as an underground conduit and any potential negative effects of soil settlement, should the pipe be left to deteriorate. If the CSLC or any other responsible agency determines that abandoning these segments in place may cause adverse effects to the specific land uses at certain locations, the abandoned sections shall be removed or shall be filled with concrete, grout, or clean drilling mud, to avoid potential impacts. The specific action shall be determined by the CSLC and other responsible agencies after review of the Applicant's letter report.

Residual Impact. The likelihood of soil contamination or other impacts resulting from improper pipe abandonment would be less than significant with implementation of Mitigation Measure S-3a.

D.2.4 Environmental Impacts and Mitigation Measures for Existing Pipeline ROW Alternative

Construction impacts for the Existing Pipeline ROW Alternative would be similar to those of the Proposed Project, as defined in Section D.2.3.3 above (Impact S-1). Mitigation Measures S-1a through S-1h would also apply to this alternative.

Using the data presented in Section D.2.1, the frequency of unintentional releases from the Existing Pipeline ROW Alternative, for all releases, regardless of release volume, is expected to be 2.88 incidents per 1,000 mile-years. For the 61.4-mile, 20-inch-diameter pipeline, the results are summarized in Tables D.2-40, D.2-41, and D.2-42 below.

Based on these spill recurrence intervals, the likelihood of a pipeline accident, and resulting injuries and fatalities are considered to be a significant (Class I) impact. There is a roughly one in eight likelihood of a fatality, and a one in two likelihood of serious injury being caused by the Proposed Project during the 50-year project life. All mitigation measures for the Proposed Project would also be recommended for this alternative.

Mitigation Segment EP-1

Mitigation Segment EP-2 would be 4 miles longer than the equivalent segment of the Existing Pipeline ROW Alternative. As discussed in Section D.4.3, this mitigation segment is proposed to consider the potential for reducing biological resource impacts. The anticipated unintentional releases per mile are the same as those given in Section D.2-7. The anticipated unintentional releases for the entire 65.4-mile alternative, including Mitigation Segment EP-1, are presented in Appendix 2.

Additionally, the unintentional release volume distribution remains the same, per mile, as any one-mile segment of new 20-inch pipe. The volume distribution for the entire 65.4-mile route, including Mitigation Segment EP-1, is presented in Appendix 2.

Table D.2-40. Anticipated Unintentional Releases from 61.4-Mile, 20-Inch-Diameter SFPP Existing Pipeline ROW Alternative

Unintentional Release Cause	Unintentional Release Rate (per 1,000 mile-years)	Pipeline Section Length (miles)	Unintentional Releases per Year	Recurrence Interval (years)
External corrosion	1.00	61.4	0.0614	16
Internal corrosion	0.19	61.4	0.0117	86
3rd party damage	0.40	61.4	0.0246	41
Human operating error	0.11	61.4	0.0068	148
Design flaw	0.03	61.4	0.0018	543
Equipment malfunction	0.37	61.4	0.0227	44
Maintenance	0.07	61.4	0.0043	233
Weld failure	0.26	61.4	0.0160	63
Other	0.45	61.4	0.0276	36
Total, all unintentional releases, regardless of volume	2.88	61.4	0.1768	6
DOT reportable unintentional releases (50 barrels or greater) – 20-inch diameter	1.10	61.4	0.0675	15
Injuries, regardless of severity	0.685	61.4	0.0421	24
Injuries requiring hospitalization, causing loss of consciousness, or preventing discharge of normal duties the day following the incident	0.150	61.4	0.0092	109
Fire	Probability for fire incidents is less than the probability of the releases shown in this table because, in addition to presence of product, a fire requires the presence of an appropriate source of ignition.			
Fatalities	0.042	61.4	0.0026	388

Table D.2-41. Anticipated Pipeline Unintentional Releases from Any One-Mile Section of the 20-Inch-Diameter SFPP Existing Pipeline ROW Alternative

Unintentional Release Cause	Unintentional Release Rate (per 1,000 mile-years)	Pipeline Section Length (miles)	Unintentional Releases per Year	Recurrence Interval (years)
External corrosion	1.00	1	0.0010	1,000
Internal corrosion	0.19	1	0.0002	5,263
3rd party damage	0.40	1	0.0004	2,500
Human operating error	0.11	1	0.0001	9,091
Design flaw	0.03	1	0.0000	33,333
Equipment malfunction	0.37	1	0.0004	2,703
Maintenance	0.07	1	0.0001	14,286
Weld failure	0.26	1	0.0003	3,846
Other	0.45	1	0.0005	2,222
Total, all unintentional releases, regardless of volume	2.88	1	0.0029	347
DOT reportable unintentional releases (50 barrels or greater)	1.10	1	0.0011	907
Injuries, regardless of severity	0.685	1	0.0007	1,460
Injuries requiring hospitalization, causing loss of consciousness, or preventing discharge of normal duties the day following the incident	0.150	1	0.0002	6,667
Fatalities	0.042	1	0.00004	23,810

Table D.2-42. Anticipated Unintentional Release Volume Distribution from 61.4-Mile, 20-Inch-Diameter SFPP Existing Pipeline ROW Alternative Route

Unintentional Release Volume, Barrels (gallons)	Anticipated Unintentional Releases Per Year – Entire 61.4-Mile Section	Anticipated Recurrence Interval (Years) – Entire 61.4-Mile Section	Anticipated Unintentional Releases Per Year – Any One-Mile Section	Anticipated Recurrence Interval (Years) – Any One-Mile Section	Anticipated Unintentional Releases Over 50-Year Project Life
All Unintentional Releases (regardless of volume)	0.1768	6	0.00288	347	8.84
Small Unintentional Release ≥1 (42)	0.1689	6	0.00275	363	8.45
≥5 (210)	0.1289	8	0.00210	476	6.45
≥10 (420)	0.1075	9	0.00175	572	5.36
≥50 (2,100)	0.0675	15	0.00110	907	3.38
Medium Unintentional Release ≥100 (4,200)	0.0512	20	0.000834	1,199	2.56
≥500 (21,000)	0.0299	33	0.000487	2,053	1.50
Large Unintentional Release ≥1,000 (42,000)	0.0236	42	0.000384	2,607	1.18
≥5,000 (210,000)	0.0083	121	0.000135	7,413	0.41
Very Large Unintentional Release ≥10,000 (420,000)	0.0042	236	0.000069	14,594	0.21

Mitigation Segment EP-2

Mitigation Segment EP-2 would be 2 miles longer than the equivalent segment of the Existing Pipeline ROW Alternative. As discussed in Section D.9 (Land Use), this segment is proposed to reduce land use impacts. The anticipated unintentional releases per mile are the same as those given in Section D.2-7. The anticipated unintentional releases for the entire 63.4-mile route are presented in Appendix 2.

Additionally, the unintentional release volume distribution remains the same, per mile, as any one-mile segment of new 20-inch pipe. The volume distribution for the entire 63.4-mile route is presented in Appendix 2.

D.2.5 Environmental Impacts of the No Project Alternative

In the coming years, the No Project Alternative would likely result in changes in the transportation of refined petroleum projects from the refiners in the San Francisco Bay Area to the distribution points in the Sacramento area. However, the distribution of volumes to be shipped, by their mode of transportation, is difficult to predict. The increased volumes would likely be transported via some mix of pipeline, rail, and truck transportation.

Impact S-4: Accidents, Injuries, and Fatalities during Product Transport

As noted earlier, the shipping of petroleum products via pipeline is generally considered to be the safest means of bulk transportation. The California State Fire Marshal, Hazardous Liquid Pipeline Risk Assessment indicated that the fatality rate for bulk transportation by rail was 40 times higher than by pipeline. The same study indicated that the fatality rate for bulk transportation by truck was 300 times higher than by pipeline. As a result, any increased volumes being shipped by truck or rail will increase the impacts to human life.

A detailed analysis of the anticipated frequency of truck and rail transportation accidents was beyond the scope of this study. However, when comparing the relative safety of pipeline, truck and rail transportation of bulk hazardous liquids, one such study of hazardous liquid transportation by various modes found the following:

- The frequency of unintentional releases was three to four times higher for a mix of rail and truck transportation than for similar volumes being transported exclusively by pipeline.
- The frequency of all injuries, regardless of severity, was roughly thirty times higher for a mix of rail and truck transportation than for similar volumes being transported exclusively by pipeline.
- The frequency of fatalities was approximately fifty times higher for a mix of rail and truck transportation than for similar volumes being transported exclusively by pipeline.
- The frequency of small releases was higher for truck and rail transportation, while the frequency of large spill volumes was higher for pipeline transportation. This was due primarily to the limited size of the truck and rail car volumes; the release size is limited to the volume of the damaged car(s).

Although a quantitative determination of the anticipated frequency of unintentional releases, injuries, and fatalities from the No Project Alternative was beyond the scope of this study, the following qualitative conclusions can be drawn based on similar analyses for other projects:

- The No Project Alternative would result in a higher total number of unintentional releases than the Proposed Project. However, the distribution of release volumes would likely differ. The No Project Alternative would likely result in a much higher frequency of small to moderate volume releases, but a lower frequency of the infrequent very high release volumes.
- The No Project Alternative would result in a higher frequency of injuries. The extent of increase would depend on the actual volumes shipped by truck or rail. The higher the volumes to be shipped via these modes of transportation, the higher the resulting differential injury rate.
- The No Project Alternative would result in a higher frequency of fatalities. Again, the magnitude of this increase would depend on the actual volumes shipped by truck or rail. The higher the volumes shipped via these modes of transportation, the higher the resulting differential fatality rate.

In the following tables, the anticipated frequency of unintentional releases from the existing 61.4-mile, 14-inch-diameter pipeline have been presented. The anticipated frequency of releases is roughly 50% higher than for the proposed new pipeline construction — 4.48 versus 2.88 releases per 1,000 mile-years.

Residual Impacts. Accidents from the No Project Alternative are more likely to occur than accidents from a new pipeline. Therefore, this alternative would result in significant impacts (Class I).

D.2.6 Mitigation Monitoring, Compliance, and Reporting Table

Table F-1 (in Section F) presents the Mitigation Monitoring table for pipeline safety. It generally identifies the impacts, the abbreviated mitigation measure, the location and the agencies that have jurisdiction to require the implementation of these mitigation measures.

Table D.2-43. Anticipated Pipeline Unintentional Releases from the Existing 61.4-Mile, 14-Inch-Diameter SFPP Pipeline

Unintentional Release Cause	Unintentional Release Rate (per 1,000 mile-years)	Pipeline Section Length (miles)	Unintentional Releases per Year	Recurrence Interval (years)
External corrosion	2.00	61.4	0.1228	8
Internal corrosion	0.19	61.4	0.0117	86
3rd party damage	1.00	61.4	0.0614	16
Human operating error	0.11	61.4	0.0068	148
Design flaw	0.03	61.4	0.0018	543
Equipment malfunction	0.37	61.4	0.0227	44
Maintenance	0.07	61.4	0.0043	233
Weld failure	0.26	61.4	0.0160	63
Other	0.45	61.4	0.0276	36
Total, all unintentional releases, regardless of volume	4.48	61.4	0.2751	4
DOT reportable unintentional releases (50 barrels or greater) – 14-inch diameter	1.30	61.4	0.0798	13
Injuries, regardless of severity	0.685	61.4	0.0421	24
Injuries requiring hospitalization, causing loss of consciousness, or preventing discharge of normal duties the day following the incident	0.150	61.4	0.0092	109
Fire	Probability for fire incidents is less than the probability of the releases shown in this table because, in addition to presence of product, a fire requires the presence of an appropriate source of ignition.			
Fatalities	0.042	61.4	0.0026	388

Table D.2-44. Anticipated Pipeline Unintentional Releases from Any One-Mile Section of the Existing 14-Inch-Diameter SFPP Pipeline

Unintentional Release Cause	Unintentional Release Rate (per 1,000 mile-years)	Pipeline Section Length (miles)	Unintentional Releases per Year	Recurrence Interval (years)
External corrosion	2.00	1	0.0020	500
Internal corrosion	0.19	1	0.0002	5,263
3rd party damage	1.00	1	0.0010	1,000
Human operating error	0.11	1	0.0001	9,091
Design flaw	0.03	1	0.0000	33,333
Equipment malfunction	0.37	1	0.0004	2,703
Maintenance	0.07	1	0.0001	14,286
Weld failure	0.26	1	0.0003	3,846
Other	0.45	1	0.0005	2,222
Total, all unintentional releases, regardless of volume	4.48	1	0.0045	223
DOT reportable unintentional releases (50 barrels or greater)	1.30	1	0.0013	769
Injuries, regardless of severity	0.685	1	0.0007	1,460
Injuries requiring hospitalization, causing loss of consciousness, or preventing discharge of normal duties the day following the incident	0.150	1	0.0002	6,667
Fire	Probability for fire incidents is less than the probability of the releases shown in this table because, in addition to presence of product, a fire requires the presence of an appropriate source of ignition.			
Fatalities	0.042	1	0.0000	23,810

Table D.2-45. Anticipated Unintentional Release Volume Distribution from the Existing 61.4-Mile, 14-Inch-Diameter SFPP Pipeline

Unintentional Release Volume, Barrels (gallons)	Anticipated Unintentional Releases Per Year – Entire 61.4-Mile Section	Anticipated Recurrence Interval (Years) – Entire 61.4-Mile Section	Anticipated Unintentional Releases Per Year – Any One-Mile Section	Anticipated Recurrence Interval (Years) – Any One-Mile Section	Anticipated Unintentional Releases Over 50-Year Project Life
All Unintentional Releases (regardless of volume)	0.2751	4	0.00448	223	13.75
Small Unintentional Release ≥1 (42)	0.2554	4	0.00416	241	12.77
≥5 (210)	0.1670	6	0.00272	368	8.35
≥10 (420)	0.1326	8	0.00216	463	6.63
≥50 (2,100)	0.0798	13	0.00130	771	3.98
Medium Unintentional Release ≥100 (4,200)	0.0620	16	0.00101	987	3.11
≥500 (21,000)	0.0360	28	0.000587	1,703	1.80
Large Unintentional Release ≥1,000 (42,000)	0.0262	38	0.000426	2,346	1.31
≥5,000 (210,000)	0.0064	155	0.000105	9,495	0.32
Very Large Unintentional Release ≥10,000 (420,000)	0.0039	259	0.000063	15,869	0.19